BOARD MEETING DATE: September 7, 2012 AGENDA NO. 32

PROPOSAL: Amend Rule 1110.2 - Emissions from Gaseous- and Liquid-Fueled Engines

SYNOPSIS: Consistent with staff's Technology Assessment findings, the proposed amendments would re-establish the previously adopted emission limits for biogas-powered internal combustion engines. The proposed amendment would provide additional time for compliance; a compliance option for a longer averaging time for engines with superior performance in achieving lower mass emissions; a compliance option that further extends the effective dates for certain engines based on a compliance flexibility fee; and include other clarifications.

COMMITTEE: Stationary Source, April 20, May 18, and June 15, 2012

RECOMMENDED ACTIONS:
Adopt the attached resolution:
1. Receiving and filing the Technology Assessment Report;
2. Certifying the CEQA Addendum to the 2008 Final Environmental Assessment; and
3. Amending Rule 1110.2 - Emissions from Gaseous- and Liquid-Fueled Engines.

Barry R. Wallerstein, D.Env.
Executive Officer

LT:JC:GQ:KO

Background

Rule 1110.2 establishes emission limits of NOx, VOC, and CO for stationary, non-emergency gaseous- and liquid-fueled engines, including the 55 engines in this source category, that are fueled by landfill or digester gas (biogas). Biogas, a by-product of municipal wastewater treatment and landfill operations, is considered a renewable energy source and is often combusted as fuel in biogas engines to produce power for onsite and/or offsite use. While they are one of several technologies available to harness power from biogas, the power produced by biogas engines has a very undesirable emissions footprint. The emission limits for new biogas engines are the highest of all engines, even higher than diesel engines with BACT and on a per unit of power produced (per Megawatt-hour, MW-hr) basis, biogas engine emissions are significantly higher than those from central power plants (as much as 55 times).

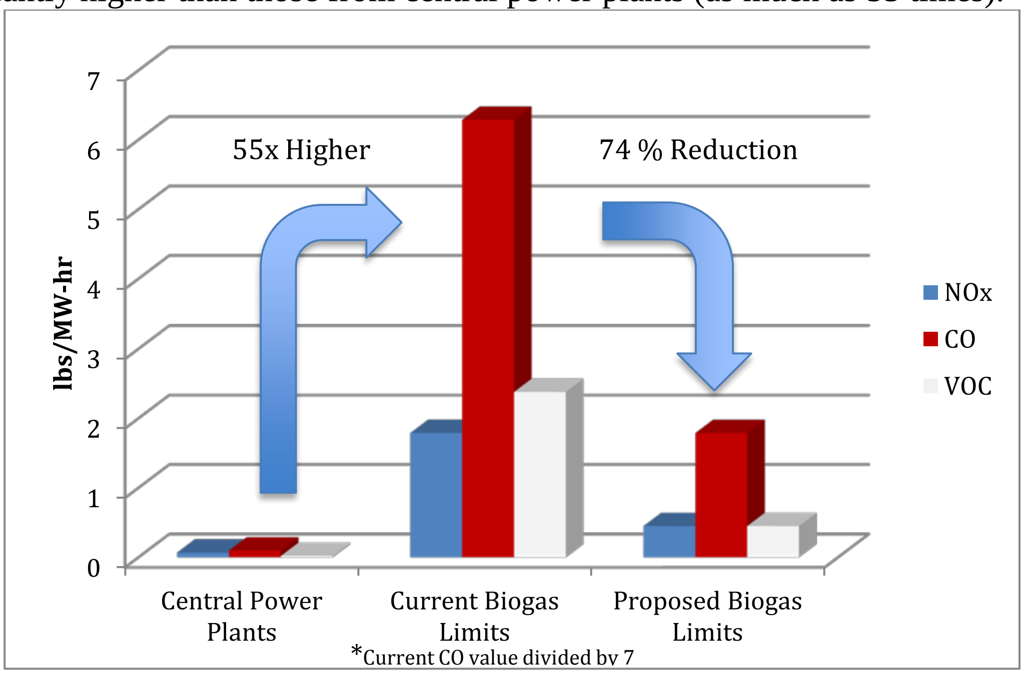


Figure 1. Emissions from Biogas ICEs versus Central Power Plants

Rule 1110.2 was amended on February 1, 2008 to lower the emission limits of natural gas and biogas engines to BACT levels for NOx and VOC and to levels close to BACT for CO. The limits for natural gas engines at or above 500 bhp took effect on July 1, 2010, while those for natural gas engines below 500 bhp took effect on July 1, 2011. Biogas engines were given until July 1, 2012 to comply with the new limits.

The amendment and adopting resolutions of Rule 1110.2 in February 2008 directed staff to conduct a Technology Assessment to address the availability, feasibility, cost-effectiveness, compliance schedule, and global warming gas impacts of biogas engine control technologies and report back to the Governing Board no later than July 2010. Immediately after the 2008 amendment, staff began work on the Technology Assessment and followed the progress of several technology demonstration projects.

In July 2010, the Governing Board received and filed an Interim Technology Assessment by staff, which summarized the biogas cleanup and biogas engine control technologies to date and the status of on-going demonstration projects. Due to the delays caused by the permit moratorium in 2009, the release of another report was recommended upon the completion of these projects. The Interim Technology Assessment concluded that feasible, cost-effective technology that could support the feasibility of the July 2012 emission limits was available, but that the delay in the demonstration projects would likely necessitate an adjustment to the July 1, 2012 compliance date of Rule 1110.2.

The Final Technology Assessment attached to the staff report summarizes staff's findings to date regarding the feasibility of the biogas engine emission limits. Data collected from a completed demonstration project at Orange County Sanitation District (OCSD) and from the Ox Mountain landfill project in the Bay Area provides substantial evidence in support of the proposed emission limits for biogas engines with the use of oxidation catalysts and selective catalytic reduction (SCR) with biogas cleanup. The technology demonstration projects have shown that technology is available that can achieve significant reductions in NOx, VOC, and CO. In addition to feasibility, the Final Technology Assessment also includes information on cost-effectiveness, compliance schedule, global warming impacts, and the impacts of potential flaring, as well as other technologies that can provide facility operators with viable alternatives for meeting the proposed amendment's compliance requirements.

Public Process

The Biogas Technology Advisory Committee was formed to assist staff with its technology assessment efforts for biogas engines. Since the 2008 amendment, staff has held nine Biogas Technology Advisory Committee meetings with representatives from affected facilities, manufacturers, consultants and other interested parties. In October 2010 staff met with the regulated community to discuss cost issues related to the emission standard adopted as part of the 2008 amendment. Since the July 2010 Interim Report, the Biogas Technology Advisory Committee met in September 2011, January 2012, April 2012, May 2012, and August 2012. Two Public Workshops were held on February 2012 and April 2012. Staff also has had numerous meetings with control equipment vendors and also manufacturers of emerging technologies that may provide an alternative to electrical power generation by traditional internal combustion methods. In addition, staff has met individually with nearly every biogas facility operator to discuss site-specific issues, technologies, long-term plans for existing biogas engines, and costs. Several site visits were also conducted by staff at the affected facilities.

Affected Facilities

Rule 1110.2 applies to stationary and portable reciprocating internal combustion engines (ICEs) over 50 brake horsepower (bhp). PAR 1110.2 affects the subset that contains engines fueled with biogas, which are those that are operated at landfills and wastewater treatment plants. There are currently 55 biogas engines operating in the Basin. Of these engines, 27 are digester gas-fueled and 28 are landfill gas-fueled. These engines are operated by 13 independent operators at 22 locations.

Proposed Amendments

The key proposed amendments can be summarized as follows:

- Extend the effective date of the previously adopted 2012 limits by three and a half years. The new effective date will be January 1, 2016 for all biogas engines. Operators that achieve early compliance by January1, 2015 will receive a refund of the biogas engine application permit fees.
- Provide a compliance option with a longer averaging time (monthly averaging the first 4 months of engine operation with 24-hour averaging thereafter) to engine operators that can demonstrate through continuous emission monitoring systems (CEMS) data emission levels at least 10 percent lower than allowable under the rule's proposed concentration limits.
- Provide an alternate compliance option to give private operators under long term fixed price power purchase agreements entered into prior to the February 1, 2008 amendments and extending beyond the January 1, 2016 compliance date additional time (up to two years beyond the compliance date) to comply with the emission limits with the payment of a compliance flexibility fee.
- Minor administrative changes and clarifications

Emission Reductions and Cost Effectiveness

The proposed amendments will result in up to 74% emission reductions on an aggregate basis. The emission reductions are estimated at 334 tons per year of NOx (0.9 tons per day), 178 tons per year of VOC (0.5 tons per day), and 7,302 tons per year of CO (20.0 tons per day). The reductions will occur in two steps. The bulk of the reductions are expected to occur during the first step and no later than January 1, 2016, while the remainder of the reductions will occur one to two years later when remaining biogas engines operating under the alternate compliance option all comply with the rule limits.

Using the District model, the cost effectiveness is estimated to range from $1,700 to $3,500 per ton of NOx, VOC, and CO/7 reduced. Staff also calculated cost effectiveness to account for additional contingencies, based on stakeholder feedback. With the additional contingencies, the cost effectiveness would range from $2,600 to

$5,900 per ton. All of the cost effectiveness estimates are within the range of estimates considered by the Governing Board as part of past rulemakings.

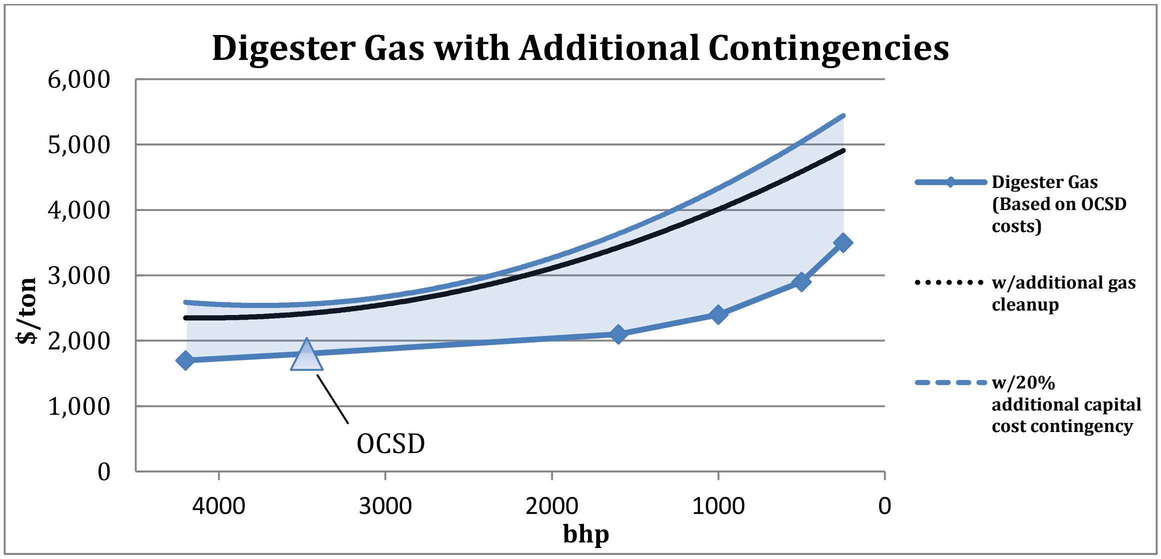


Figure 2. Cost Effectiveness for Digester Gas (Catalytic Aftertreatment)

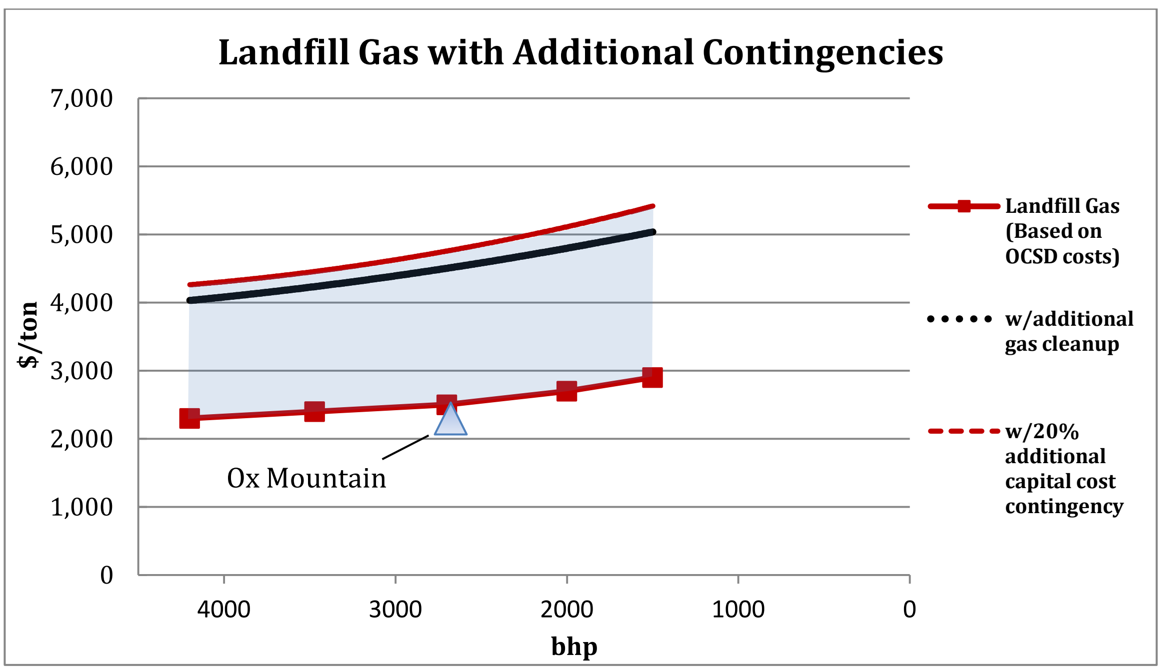


Figure 3. Cost Effectiveness for Landfill Gas (Catalytic Aftertreatment)

Key Issues

1. *Time for Implementation*. Stakeholders are requesting five years or an effective date of July 1, 2017 to properly plan, design, purchase, install the control equipment, and comply with the requirements of the rule.

   Response: The current compliance schedule, as proposed, gives operators three and a half years for compliance, which is already one and a half years longer than what is typically offered to other regulated entities subject to similar control requirements and what was offered as part of the 2008 amendments. This extended schedule provides reasonable additional time for the completion of on-going projects and the stakeholders' decision making process for selecting the right control technology for their site. For those facilities that entered into long term power purchase agreements prior to the February 1, 2008 amendments and, arguably, unaware of the upcoming 2008 amendments, an alternate compliance option will make it possible to defer compliance up to two years from the effective date with the payment of a compliance flexibility fee, provided such contracts don't expire prior to the January 1, 2016 effective date.

2. *Cost of Compliance*. Stakeholders have commented that the capital and operating costs for cleaning up the biogas are very high and post-combustion control technologies such as Catalytic Oxidation and Selective Catalytic Reduction (SCR) are expensive to install and operate and argued that many of them will resort to flaring as a less costly alternative.

   Response: Although there are significant costs involved with installing and operating the equipment, the environmental benefits are significant and, therefore, very cost effective. Given the state of air quality in the South Coast Air Basin and the size of the "black box," or Section 182(c)(5), emission reductions needed to meet the ambient air quality standards, it is not only reasonable, but also necessary, to rely on the reductions to be achieved with the proposed amendments. Staff has also analyzed extensively the potential impacts of flaring. While staff acknowledges that flaring of a renewable energy source is undesirable, biogas flaring, except for a small Greenhouse Gas disbenefit, has a much lower criteria pollutant footprint compared to that from biogas engines, even if one accounts for the power that needs to be generated by central power plants.

AQMP and Legal Mandates

The California Health and Safety Code requires the AQMD to adopt an Air Quality Management Plan to meet state and federal ambient air quality standards and adopt rules and regulations that carry out the objectives of the AQMP. The proposed amendments of Rule 1110.2 will provide additional reductions that will aid in attaining more stringent federal ozone and particulate matter standards. Reductions in NOx will help in attaining the federal 24-hour and annual average $PM_{2.5}$ standard by 2014 and 2015, while reductions in NOx and VOC will aid in attaining the ozone standard in 2023.

California Environmental Quality Act (CEQA) Analysis

Pursuant to the California Environmental Quality Act (CEQA) and AQMD Rule 110, SCAQMD staff has reviewed PAR 1110.2 to identify the appropriate CEQA document for evaluating potential adverse environmental impacts. Because the proposed project consists of changes to a previously approved project evaluated in a certified CEQA document and none of the conditions described in CEQA Guidelines §15162 calling for preparation of a subsequent CEQA document would occur, staff has concluded that an Addendum to the December 2007 Final Environmental Assessment: Proposed Amended Rule 1110.2 – Emissions from Gaseous- and Liquid-Fueled Internal Combustion Engines (ICEs), prepared pursuant to CEQA Guidelines §15164, is the appropriate CEQA document for the proposed project. Pursuant to CEQA Guidelines §15164(c) an addendum need not be circulated for public review.

Socioeconomic Analysis

PAR 1110.2 would re-establish the concentration limits for biogas-fired engines at a later date, that is from 2012 to 2016. Furthermore, the universe of affected biogas-fired engines by PAR 1110.2 is currently at 55 engines, reduced from 65 engines evaluated as part of the 2008 amendments, which is a reduction of 14 percent of the total brake horsepower.

The technologies for complying with the concentration limits have remained the same since 2008 and costs of these technologies have stayed relatively constant. The additional time for compliance and fewer affected engines would result in fewer costs to the affected universe as a whole, compared to what was analyzed as part of the 2008 amendments. Therefore, given the fact that there are fewer engines to control and the control costs remained relatively constant compared to what was evaluated as part of the Socioeconomic Assessment conducted for the 2008 amendments to Rule 1110.2, the findings and conclusions of that analysis remain valid for this proposed amendment as well.

Resource Impacts

Existing staff resources are adequate to implement the proposed amendments.

Attachments

A. Summary of Proposal
B. Rule Development Process
C. Key Contacts List
D. Resolution and Attachment 1 to the Resolution
E. Proposed Amended Rule
F. Staff Report
G. Assessment of Available Technology for Control of NOx, CO, and VOC Emissions from Biogas-Fueled Engines—Final Report
H. Final Socioeconomic Assessment for Proposed Amended Rule 1110.2—Emissions from Gaseous- and Liquid-Fueled Engines, January 2008
I. Addendum to Final Environmental Assessment for Proposed Amended Rule 1110.2—Emissions from Gaseous- and Liquid-Fueled Engines
J. Final Environmental Assessment: Proposed Amended Rule 1110.2—Emissions from Gaseous- and Liquid-Fueled Engines, December 2007

ATTACHMENT A

SUMMARY OF PROPOSAL

Proposed Amended Rule 1110.2 – Emissions from Gaseous- and Liquid-Fueled Engines
• Re-establish the effectiveness of the previously adopted 2012 limits for biogas engines of 11 ppmv NOx, 30 ppmv VOC, and 250 ppmv CO, each corrected to 15% O2 on a dry basis. Allow operators three and a half more years to comply with the emission limits. The new effective date will be July 1, 2016 for all biogas engines. • Biogas engines achieving early compliance by January 1, 2015 will have their permit application fees refunded. • Provide a compliance option with a longer averaging time to engine operators that can demonstrate through continuous emissions monitoring system (CEMS) data emission levels at least 10 percent lower than allowable under the rule's proposed concentration limits over a four month period. An operator may utilize a monthly averaging time for the first 4 months of engine operation and up to a 24 hour averaging time thereafter. • Provide a compliance option where engine operators that have entered into long term fixed price power purchase agreements before February 1, 2008 and extending beyond January 1, 2016 will receive additional time to comply (up to two years beyond January 1, 2016) with the payment of a compliance flexibility fee of $47/bhp-yr. • CEMS data procedures: not including zero data in averaging and using substitute data when NOx and/or CO emissions data have not been collected and do not meet the requirements of Rules 218 and 218.1. • Rule clarification for allowing oxygen set point adjustments for maintaining compliance without returning to a more frequent portable analyzer testing schedule. • Rule clarification for allowing a shutdown exemption period not lasting more than 30 minutes. • Clarification in Staff Report allowing the temporary removal of a catalyst during the four-hour exemption period following an engine overhaul or major repair requiring removal of a cylinder head. • Clarification in Staff Report allowing source tests in lieu of portable analyzer checks in the event a scheduled portable analyzer emissions check occurs during the same monitoring period as a regularly scheduled source test. • Minor administrative changes to provide clarity with respect to references within the rule.

ATTACHMENT B

RULE DEVELOPMENT PROCESS

Proposed Amended Rule 1110.2 – Emissions from Gaseous- and Liquid-Fueled Engines

Proposed Amended Rule 1110.2 Initial Rule Development
June 2011

Biogas Technology Advisory Committee Meeting
September 21, 2011
January 10, 2012

Public Workshop *(2,105 Notices mailed)*
February 23, 2012

Biogas Technology Advisory Committee Meeting/
Public Workshop *(2,105 Notices mailed)*
April 4, 2012

Stationary Source Committee Meeting
April 20, 2012

Biogas Technology Advisory Committee Meeting
May 16, 2012

Stationary Source Committee Meeting
May 18, 2012

Set Hearing
June 1, 2012

Stationary Source Committee Meeting
June 15, 2012

Biogas Technology Advisory Committee Meeting
August 8, 2012

Public Hearing
September 7, 2012

Total time spent in rule development: 15 months

ATTACHMENT C

KEY CONTACTS LIST

<u>Agency Representatives</u>
Bay Area Air Quality Management District (BAAQMD)
California Air Resources Board (CARB)
California Association of Sanitation Agencies (CASA)
Orange County Waste and Recycling (OCWR)
Southern California Alliance of Publicly Owned Treatment Works (SCAP)
U. S. Environmental Protection Agency (EPA)

<u>Affected Facilities</u>
Brea Parent 2007, LLC
City of Riverside
City of San Bernardino Municipal Water Department
Eastern Municipal Water District (EMWD)
Fortistar
Inland Empire Utilities Agency (IEUA)
J&A Whittier
Los Angeles County Sanitation District (LACSD)
Montauk Energy
Orange County Sanitation District (OCSD)
Riverside County Waste Management Department
South Orange County Wastewater Authority (SOCWA)
Waste Management

<u>Other Interested Parties</u>
Applied Filter Technology
Environ Strategy Consultants, Inc.
ESC Corporation
Flex Energy
Fuel Cell Energy
Johnson Matthey
Miratech Corporation
NOxTech
Sierra Club
Southern California Edison
Southern California Gas Company
Representatives from other companies and other interested individuals

ATTACHMENT D

RESOLUTION NO. - __________

A Resolution of the South Coast Air Quality Management District (AQMD) Governing Board Certifying the Addendum to the Final Environmental Assessment for Proposed Amended Rule 1110.2 – Emissions from Gaseous- and Liquid-Fueled Internal Combustion Engines.

A Resolution of the AQMD Governing Board amending Rule 1110.2 – Emissions from Gaseous- and Liquid-Fueled Engines.

WHEREAS, the AQMD Governing Board has determined with certainty that Proposed Amended Rule 1110.2 is considered a "project" pursuant to the terms of the California Environmental Quality Act (CEQA); and

WHEREAS, the AQMD has had its regulatory program certified pursuant to Public Resources Code Section 21080.5 and has conducted CEQA review pursuant to such program (AQMD Rule 110); and

WHEREAS, the AQMD was the lead agency and prepared the 2007 Final Environment Assessment (EA) for Proposed Amended Rule 1110.2 – Emissions from Gaseous- and Liquid-Fueled Internal Combustion Engines (SCAQMD No. 280307JK, December 2007) for the 2008 Amendments to Rule 1110.2, which was certified on January 4, 2008; and

WHEREAS, it was concluded that the proposed amendments to Rule 1110.2 would not generate any new significant adverse environmental impacts or make existing significant adverse impacts identified in the 2007 Final EA Proposed Amended Rule 1110.2 worse and, therefore, has concluded that an Addendum prepared pursuant to CEQA Guidelines §16164 is the appropriate CEQA document for the proposed project; and

WHEREAS, as Lead Agency for Proposed Amended Rule 1110.2 under CEQA, the AQMD prepared an Addendum to the 2007 Final EA; and

WHEREAS, pursuant to CEQA Guidelines §15164(c), an Addendum need not be circulated for public review; and

WHEREAS, the AQMD Governing Board voting on Proposed Amended Rule 1110.2, has reviewed, considered the Addendum to the 2007 Final EA along with the 2007 Final EA; and

WHEREAS, the AQMD Governing Board finds and determines, taking into consideration the factors in §(d)(4)(D) of the Governing Board Procedures, that any modifications adopted which have been made to Proposed Amended Rule 1110.2, since notice of public hearing was published do not significantly change the meaning of the proposed rule within the meaning of the Health and Safety Code Section 40726 and do not constitute conditions described in CEQA Guidelines §15162 requiring preparation of a subsequent CEQA document; and

WHEREAS, the AQMD Governing Board has determined that a need exists to amend Rule 1110.2 – Emissions from Gaseous- and Liquid-Fueled Engines, for the reasons contained in the Board Letter; and

WHEREAS, the AQMD Governing Board obtains its authority to adopt, amend, or rescind rules and regulations from Sections 40000, 40001, 40440, 40500, 40501.3, 40506, 40510, 40510.5, 40512, 40522, 40522.5, 40523, 40702, 40725 through 40728, and 44380 of the California Health and Safety Code; and

WHEREAS, the AQMD Governing Board has determined that Rule 1110.2 – Emissions from Gaseous- and Liquid-Fueled Engines, as proposed to be amended, is written or displayed so that its meaning can be easily understood by the persons directly affected by it; and

WHEREAS, the AQMD Governing Board has determined that Rule 1110.2 – Emissions from Gaseous- and Liquid-Fueled Engines, as proposed to be amended, is in harmony with, and not in conflict with or contradictory to, existing statutes, court decisions, or state or federal regulations; and

WHEREAS, the AQMD Governing Board has determined that Rule 1110.2 – Emissions from Gaseous- and Liquid-Fueled Engines, as proposed to be amended, does not impose the same requirements as any existing state or federal regulation, and the proposed amended rule is necessary and proper to execute the powers and duties granted to, and imposed upon, the AQMD; and

WHEREAS, the AQMD Governing Board, in amending and adopting this regulation, references the following statutes which the District hereby implements, interprets, or makes specific: California Health and Safety Code Sections 40440(a) (rules to carry out the Air Quality Management Plan), 40440(c) (cost effectiveness), 41508, 41700, and Federal Clean Air Act Section 172(c)(1) (RACT); and

WHEREAS, the AQMD Governing Board has determined that the Final Socioeconomic Assessment approved for the 2008 amendments to Rule 1110.2 remain valid for this proposed amendment, since there are fewer engines to control and the control costs have remained relatively constant since the 2008 Socioeconomic Assessment was conducted; and

WHEREAS, the AQMD Governing Board has determined that the 2008 Socioeconomic Assessment for Proposed Amended Rule 1110.2 – Emissions from Gaseous- and Liquid-Fueled Internal Combustion Engines is still consistent with the provisions of Health and Safety Code Sections 40440.8, 40728.5 and 40920.6; and

WHEREAS, the AQMD Governing Board has determined that the 2008 Socioeconomic Assessment for Proposed Amended Rule 1110.2 – Emissions from Gaseous- and Liquid-Fueled Internal Combustion Engines is still consistent with the March 17, 1989 Board Socioeconomic Resolution for rule adoption; and

WHEREAS, the AQMD Governing Board has determined that Proposed Amended Rule 1110.2 – Emissions from Gaseous- and Liquid-Fueled Internal Combustion Engines would have fewer costs to the affected industries than what was described in the 2008 Socioeconomic Assessment; and

WHEREAS, a public hearing has been properly noticed in accordance with the provisions of Health and Safety Code Section 40725; and

WHEREAS, the AQMD Governing Board has held a public hearing in accordance with all the provisions of law; and

WHEREAS, the AQMD specifies the Manager of Rule 1110.2 – Emissions from Gaseous- and Liquid-Fueled Engines as the custodian of the documents or other materials which constitute the record of proceedings upon which the adoption of this proposed amendment is based, which are located at the South Coast Air Quality Management District, 21865 Copley Drive, Diamond Bar, California; and

WHEREAS, at the conclusion of the public hearing, the AQMD Board may make other amendments to Proposed Amended Rule 1110.2 which are justified by the evidence presented, or may decline the amendments or adoption; and

NOW, THEREFORE, BE IT RESOLVED, that the AQMD Governing Board does hereby certify that the Addendum to the 2007 Final EA for Proposed Amended Rule 1110.2 – Emissions from Gaseous- and Liquid-Fueled Internal Combustion Engines, was completed in compliance with the CEQA statutes and Guidelines; and finds that the Addendum to the 2007 Final EA along with the 2007 Final EA for Proposed Amended Rule 1110.2 were presented to the Governing Board, whose members reviewed, considered and approved the information therein prior to acting on Proposed Amended Rule 1110.2 – Emissions from Gaseous- and Liquid-Fueled Internal Combustion Engines; and finds that the Addendum to the 2007 Final EA along with the 2007 Final EA for Proposed Amended Rule 1110.2 reflect the AQMD's independent judgment; and

BE IT FURTHER RESOLVED, that because no significant adverse environmental impacts were identified as a result of implementing Proposed Amended Rule 1110.2, Findings, a Statement of Overriding Considerations, and a Mitigation Monitoring Plan are not required; and

BE IT FURTHER RESOLVED, that because the CEQA document attached herein is an Addendum to the 2007 Final Environmental Assessment for Proposed Amended Rule 1110.2 – Emissions from Gaseous- and Liquid-Fueled Internal Combustion Engines, the *Attachment 1 to the Governing Board Resolution for Proposed Amended Rule 1110.2 – Emissions from Gaseous- and Liquid-Fueled Internal Combustion Engines (ICEs) Statement of Findings, Statement of Overriding Considerations and Mitigation Monitoring Plan*, prepared for the 2008 amendments to Rule 1110.2 applies to the currently proposed amendments to Rule 1110.2 and, therefore, is attached herein and incorporated by reference; and

BE IT FUTHER RESOLVED, that the AQMD Governing Board directs staff to apply the funds collected from the Compliance Flexibility Fee to the AQMD's leaf blower program and any other similar NOx reduction programs pursuant to protocols approved under District rules which staff determines, in consultation with District Counsel, will not call for the preparation of a subsequent environmental assessment pursuant to CEQA guidelines section 15162; and

BE IT FURTHER RESOLVED, that the AQMD Governing Board directs staff, in amending this rule, to continue its technology/rule implementation assessment efforts by working collaboratively with all interested stakeholders and other interested parties in monitoring the performance of on-going demonstration and other commercial biogas control technology projects and report back to the Stationary Source Committee periodically, beginning no later than July 1, 2013; and

BE IT FUTHER RESOLVED, that the AQMD Governing Board directs staff, in amending this rule, to work collaboratively with all interested stakeholders and other interested parties in monitoring the effectiveness of the missing data provisions for continuous emission monitoring systems (CEMS) on biogas-fired engines, and make appropriate changes to the rule, if necessary, no later than January 1, 2015.

BE IT FURTHER RESOLVED, that the AQMD Governing Board does hereby receive and file the Final Technology Assessment Report for Biogas Engines; and

BE IT FURTHER RESOLVED, that the AQMD Governing Board does hereby amend, pursuant to the authority granted by law, Rule 1110.2 – Emissions from Gaseous- and Liquid-Fueled Engines, as set forth in the attached and incorporated herein by this reference.

Date:____________________ ______________________________________

Clerk of the Boards

SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT

Attachment 1 to the Governing Board Resolution for Proposed Amended Rule 1110.2 – Emissions from Gaseous- and Liquid-Fueled Internal Combustion Engines (ICEs)

Statement of Findings, Statement of Overriding Considerations and Mitigation Monitoring Plan

December 2007

SCAQMD No. 280307JK

Executive Officer
Barry R. Wallerstein, D.Env.

Deputy Executive Officer
Planning, Rule Development, and Area Sources
Elaine Chang, DrPH

Assistant Deputy Executive Officer
Planning, Rules, and Area Sources
Laki Tisopulos, Ph.D, P.E.

Planning and Rules Manager
Planning, Rule Development and Area Sources
Susan Nakamura

Author:	James Koizumi	Air Quality Specialist
Technical Assistance:	Alfonso Baez, M.S,	Senior Air Quality Engineer
	Howard Lange, Ph.D.	Air Quality Engineer II
Reviewed By:	Steve Smith, Ph.D.	Program Supervisor, CEQA
	Martin Kay, P.E., M.S.,	Program Supervisor, Planning, Rules, and Area Sources
	Barbara Baird	Principal Deputy District Counsel

SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT
GOVERNING BOARD

CHAIRMAN: WILLIAM A. BURKE, Ed.D.
Speaker of the Assembly Appointee

VICE CHAIRMAN: S. ROY WILSON, Ed.D.
Supervisor, Fourth District
Riverside County Representative

MEMBERS:

MICHAEL D. ANTONOVICH
Supervisor, Fifth District
Los Angeles County Representative

BILL CAMPBELL
Supervisor, Third District
County of Orange

JANE W. CARNEY
Senate Rules Committee Appointee

RONALD O. LOVERIDGE
Mayor, City of Riverside
Cities Representative, Riverside County

JOSEPH K. LYOU, Ph.D.
Governor’s Appointee

GARY OVITT
Supervisor, Fourth District
San Bernardino County Representative

JAN PERRY
Councilmember, Ninth District
Cities Representative, Los Angeles County, Western Region

MIGUEL A. PULIDO
Mayor, City of Santa Ana
Cities Representative, Orange County

TONIA REYES URANGA
Councilmember, City of Long Beach
Cities Representative, Los Angeles County, Eastern Region

DENNIS YATES
Mayor, Chino
Cities Representative, San Bernardino County

EXECUTIVE OFFICER:
BARRY R. WALLERSTEIN, D.Env.

TABLE OF CONTENTS

INTRODUCTION

Proposed amended Rule (PAR) 1110.2 – Emissions from Gaseous- and Liquid-Fueled Internal Combustion Engines (ICEs), is a "project" as defined by the California Environmental Quality Act (CEQA) (California Public Resources Code §§21000 et seq.). The South Coast Air Quality Management District (SCAQMD) is the lead agency for the proposed project and, therefore, has prepared an Environmental Assessment (EA) pursuant to CEQA Guidelines §15252 and SCAQMD Rule 110. The purpose of the EA is to describe the proposed project and to identify, analyze, and evaluate any potentially significant adverse environmental impacts that may result from adopting and implementing the proposed project. The Draft EA was circulated to the public for a 45-day review and comment period from November 2, 2007, to December 18, 2007. The SCAQMD received one comment letter during the 45-day public review and comment period. Responses were prepared for the comments received during the comment period.

Note that some modifications and updates have been made to the proposed amended regulation since the release of the Draft EA based on input from the regulated industry and other parties to the rule development staff. Thus, some changes were necessary to make the revised Draft EA into a Final EA. However, these modifications and updates were evaluated by staff and it was concluded that they do not constitute "significant new information"[1] and, therefore, do not require recirculation of the document pursuant to CEQA Guidelines §15088.5.

SUMMARY OF THE PROPOSED PROJECT

PAR 1110.2 partially implements the 2007 AQMP Control Measure MSC–01 – Facility Modernization, which requires facilities not participating in the NOx Regional CLean Air Incentives Market (RECLAIM) Program to retrofit or replace existing equipment at the end of a predetermined life span to achieve NOx emissions equivalent to best available control technology (BACT). In addition to achieving NOx emission reductions equivalent to BACT, another objective of PAR 1110.2 is to achieve further VOC and CO emission reductions based on the cleanest available technologies. PAR 1110.2 would also increase engine compliance through improved monitoring, recordkeeping and reporting. PAR 1110.2 would also implement SB 1298 distributed generation (DG) emission standards for new electrical generating engines. Finally, a major objective of PAR 1110.2 is to address and correct issues also identified by EPA relative to the existing version of Rule 1110.2, so it can be approved for incorporation into the SIP.

[1] Pursuant to CEQA Guidelines §15088.5, "Significant new information" requiring recirculation include, for example, a disclosure showing that:

(a) A new significant environmental impact would result from the project or from a new mitigation measure proposed to be implemented.
(b) A substantial increase in the severity of an environmental impact would result unless mitigation measures are adopted that reduce the impact to a level of insignificance.
(c) A feasible project alternative or mitigation measure considerably different from others previously analyzed would clearly lessen the environmental impacts of the project, but the project's proponents decline to adopt it.
(d) The draft EA was so fundamentally and basically inadequate and conclusory in nature that meaningful public review and comment were precluded.

Staff proposes the following amendments to Rule 1110.2:

- Strengthen source testing requirements, add an inspection and monitoring plan, install air-to-fuel ratio controllers, and additional CEMS requirements for groups of engines over 1,500 horsepower to improve compliance. An exception from the quarterly CO monitoring is included for diesel and other lean-burn engines that are subject or Regulation XX or have a NOx CEMs and that are not subject to a CO limit more stringent than 2000 ppm. The engines would still be subject to the I&M plans
- Eliminate the efficiency correction of the current NOx and VOC emission limits, except for biogas engines until 2012 where operators limit natural gas usage to 10 percent of total fuel use and test for actual engine efficiency. Eliminate the efficiency correction of the current NOx and VOC emission limits for biogas engines after 2012. The calculation of the monthly facility biogas use percentage may exclude natural gas fired during: any electrical outage at the facility; Stage 2 or higher electrical emergencies called by the California Independent System Operator Corporation; and when precipitation causes a sewage treatment plant to exceed its design capacity. The Executive Officer may approve the burning of more than ten percent natural gas in a land fill or digester gas-fired engine, when it is necessary, if the engine required more natural gas in order for waste heat recovery boiler to provide enough thermal energy to operate a sewage treatment plant, and other boilers at the facility are unable to provide the necessary thermal energy.
- Reduce emissions consistent with the 2007 AQMP, new NOx and VOC emission limits equivalent to current BACT and a reduction of the CO limit from 2000 ppm to 250 ppm. These limits will phase in from 2010 to 2012.
- Require new electrical generating engines to partially comply with CARB DG standards.
- Clarify the exemption status of non-road engines, and remove the emission standard requirements for portable engines.
- Remove exemptions for ski area engines and engines outside South Coast and Salton Sea Air Basins
- Add new exemptions for startups, overhauls, and initial commissioning of engines.
- Include in the resolution direction for staff to not submit the 2012 biogas limits as part of the SIP submittal, conduct a technology assessment to assure that cost-effective technology is available for biogas engines to comply with the proposed biogas limits by 2010.

SIGNIFICANT ADVERSE IMPACTS WHICH CAN BE REDUCED BELOW A SIGNIFICANT LEVEL OR WERE CONCLUDED TO BE INSIGNIFICANT

The EA identified health risk from diesel emergency engine exhaust particulate and global warming as potentially significant adverse environmental impacts that can be reduced to a level determined not to be significant. There were two environmental topics, energy and solid/hazardous waste that were identified as potentially significant in the NOP/IS, but were determined not to be significant in the EA.

Health Risk from Diesel Exhaust Particulate

Health risk is evaluated on a localized level by evaluating the adverse impacts of a facility on the near-by community. The proposed project would generate potential health risks from diesel truck trips associated with ammonia, LNG and diesel fuel. Facility operators who replace biogas ICEs with alternative technologies instead of complying with PAR 1110.2 may need diesel emergency engines to make up energy losses due to efficiency differences between the biogas ICEs and alternative technologies. Non-biogas facility operators who replace ICEs with electric motors may need diesel emergency engines to provide energy equivalent to the non-biogas ICE during emergencies.

The worst-case carcinogenic health risk could occur at a facility that had both biogas and non-biogas emergency engines. However, the carcinogenic health risk at any facility with both biogas and non-biogas emergency engines is expected to be below the sum of the health risk of the biogas facility with the largest carcinogenic risk and the non-biogas facility with the largest carcinogenic health risk (3.4 in one million + 18 in one million = 21.4 in one million), which is greater than the significance threshold of ten in a million ($1.0x10^{-5}$). Non-carcinogenic health risk was not determined to be significant. Therefore, PAR 1110.2 would be significant for carcinogenic health risk from diesel particulate emissions.

To further reduce diesel PM emissions diesel particulate filters (DPFs) will be required for any emergency diesel backup generators used at non-biogas facilities where operators install electric motors and the carcinogenic health risk exceeds 10 in one million ($1x10^{-5}$). DPFs allow exhaust gases to pass through the filter medium, but trap diesel PM. Depending on engine baseline emissions and emission test method or duty cycle, DPFs can achieve a PM emission reduction of greater than 85 percent. DPFs installed on diesel backup generators are, however, expected to reduce significant adverse cancer risks to less than significant. The maximum cancer risk at the largest non-biogas facility can be reduced from approximately 18 in one million (1.8×10^{-5}) to approximately 4.5 in one million (4.5×10^{-6}), which is less than the SCAQMD's cancer risk significance threshold of 10 in one million (1.0×10^{-5}). Even if the carcinogenic heath risk from both the biogas and non-biogas facilities were added together (21.4 in one million or 2.14×10^{-5}), DPF would reduce the carcinogenic health risk to less than significant ($2.14 \times 10^{-5} \times (1-0.85) = 3.21$ in one million). Many engines can also limit their testing to be less than 30 hours per year to reduce carcinogenic health risk to below 10 in one million.

Global Warming

Preliminary evaluation of the proposed project indicated that it could result in a net increase in CO2 emissions (a greenhouse gas), primarily from construction activities to install control devices, new engines, etc. However, SCAQMD staff assumed for the CEQA analysis that, for some categories of ICEs, it may be less costly to install electric motors than comply with PAR 1110.2. SCAQMD staff identified 225 ICEs were it would be less costly to install electric motors. To provide a conservative analysis, staff assumed that operators of only 75 percent of these engines, 169 engines, would install electric motors. Electric motors are estimated to have a lifespan of 10 years. For the purposes of addressing the GHG impacts of PAR 1110.2, the overall impacts of CO2 emissions from the project were estimated and evaluated from initial implementation of the proposed project in 2009 through 2019 (i.e., over the lifespan of the electric motors). While the analysis was only completed over the lifespan of the electric motor, it is expected that the reduction would continue, since facility operators would be expected to replace electric motors with another electric motor once the original is replaced. The analysis also took into account CO2 emission increases from utilities to produce electricity to run the electric motors.

It is possible that fewer than 169 non-biogas engines could be replaced with electric motors, but, given the lower costs of installing and operating electric motors, it is likely that at least 15 non-biogas engines or more would be replaced with electric motors. As a result, the analysis only took CO2 emission reduction credit for the replacement of 15 ICES with electric motors. The analysis showed that the CO2 emission reductions from PAR 1110.2 with replacing ICEs with electric motors were greater than the CO2 emission increases expected from PAR 1110.2 without replacing ICEs with electric motors. Therefore, PAR 1110.2 is assumed to be less than significant for global warming.

Energy

Total Energy Impacts

Under the worst-case energy scenario (replacing digester gas engines with microturbines and landfill gas engines with LNG plants), PAR 1110.2 would reduce natural gas used by at least 181,719 MMBtu per year, which includes the voluntary replacement of existing non-biogas engines with electric motors where it costs less than complying with PAR 1110.2. The total electricity production loss by the worst-case biogas scenario (replacing digester gas engines with microturbines and landfill gas engines with LNG plants) would be 576,527 MW-hours per year which is less than one percent of 120,194 GW-hours per year available in Southern California. The maximum amount of diesel used in worst-case construction and operations would be 1,871 gallons of diesel per day, which is less than one percent of the 10 million gallons consumed per day in California, and therefore is less than significant.

Renewable Energy Impacts

A technical assessment will be completed in 2010, which will verify that PAR 1110.2 would not cause biogas facility operators to replace existing ICEs with continuous flaring. If the technology assessment shows potential for flaring or that feasible control options for biogas engines are not available, staff will return to the Governing Board with a proposal to address any new significant adverse impacts. Because of the technology assessment under PAR 1110.2, SCAQMD staff believes that facilities operators will either use add-on control or replace ICEs with alternative technologies that would either generate electricity or LNG; there would be only adverse impacts to renewable energy supplies from efficiency losses between the existing ICEs and the ICEs with add-on control or ICE replacement technologies. The largest electrical loss from renewable energy sources because of differences in efficiency between alternative technologies and the existing ICEs would be 101,013 MW-hours per year for the microturbines compliance option.

There may be adverse energy impacts in an individual government program, but any energy losses other than from efficiency losses from one program may be made up in another program. For example, if a landfill gas facility operator chooses to replace an existing biogas ICEs with a LNG facility, not only would there be a loss of electricity generation, but the LNG facility would need energy from the grid to operate. However, the landfill gas would not be wasted, but treated and sold as LNG, which is a renewable fuel. While this might affect the California's Renewables Portfolio Standard (RPS), which focuses only on electricity, it would assist renewable fuel/biomass goals under Governor Schwarzenegger's Executive Order S-06-06. Therefore, while

Solid/Hazardous Waste

The NOP/IS stated that solid/hazardous waste might be significantly adversely impacted by PAR 1110.2. Adverse solid/hazardous waste impacts are associated with the replacement of ICEs and the disposal of catalysts. The replacement of ICEs would occur once during construction. The replacement of catalyst would occur both during construction and operation. An analysis was completed that compared the capacities of existing solid and hazardous waste landfills and it was determined that the adverse solid/hazardous waste impacts associated with PAR 1110.2 would not be significant.

SIGNIFICANT ADVERSE IMPACTS THAT CANNOT BE REDUCED BELOW A SIGNIFICANT LEVEL

The Initial Study identified air quality, energy, hazards and hazardous materials, and solid/hazardous waste as areas that may be adversely affected by the proposed project. During the public comment period on the Notice of Preparation and Initial Study (NOP/IS) for the proposed project, April 26, 2007 to May 25, 2007, SCAQMD staff received comments suggesting that the proposed project could create significant adverse aesthetic impacts. Potential adverse impacts to these five environmental areas were further analyzed in the Draft EA. Potential adverse energy and solid/hazardous waste impacts were determined to be less than significant.

It was assumed that operators of biogas systems will comply with PAR 1110.2 by controlling emissions from ICEs with SCR or NOxTech systems or replace the ICE with an alternative technology that would not be regulated by PAR 1110.2, such as, boilers, gas turbines, microturbines, fuel cells or biogas to LNG facilities. Emission reductions from ICEs controlled by SCR or NOxTech systems were estimated based on PAR 1110.2 limits. The emission reductions anticipated for PAR 1110.2 are based on the assumption that operators of biogas facilities can comply with PAR 1110.2 by installing control equipment onto their equipment. However, based on comments received by the regulated industry, operators may replace biogas engines with alternative technologies and, thus, would no longer be subject to PAR 1110.2. If biogas operators choose to replace ICEs with alternative technologies (gas turbines, microturbines, LNG plants, etc.), the alternative technologies would be subject to other regulatory requirements such as Regulation XIII. The follow is a description of each replacement technology.

To account for the possibility that affected operators may install alternative technologies; staff has calculated the potential emission reduction effects if all affected biogas engines are replaced with alternative technologies. To address concerns of commenters about flaring and biogas compliance options, which have not been verified, SCAQMD staff has committed to a technology assessment in 2010. If the technology assessment shows the potential for flaring, then staff will return to the Governing Board with a proposal addressing any new significant adverse impacts. Facility operators who replace ICEs with fuel cells would not generate any appreciable emissions, so emissions would essentially be zero. The analysis assumes that facility operators who replace ICEs with biogas to LNG facilities would generate emissions from boilers used to produce heat for the process and would use electric motors, which would be powered by electricity from the grid.

The EA analyzed potential adverse impacts from five different biogas compliance options: NOx, VOC and CO controls added to biogas ICEs; biogas ICEs replaced with gas turbines; biogas ICEs replaced with microturbines; digester gas ICEs replaced with gas turbines and landfill gas ICEs replaced with LNG plants; digester gas ICEs replaced with microturbines and landfill gas ICEs replaced with LNG plants.

The analysis assumes that facility operators who replace ICEs with biogas to LNG facilities would generate emissions from boilers used to produce heat for the process and would use electric motors, which would be powered by electricity from the grid. LNG plants require substantial area because of the size and number of components needed to collect, scrub and cool biogas into LNG. Not all biogas facilities have enough space to support an LNG plant. The analysis of the effects of replacing ICEs with LNG plants assumes that only landfill gas facilities have enough area to allow installation of an LNG plant.

Aesthetics

Commenters stated that facility operators might replace existing diesel engines with diesel engine alternatives such as, gas turbines, microturbines, fuel cells, electric motors, boilers, or biogas to liquefied natural gas (LNG) plants. Physical modifications that may be necessary to comply with alternatives to complying with PAR 1110.2 might significantly alter the aesthetics of an existing facility. Therefore, PAR 1110.2 was determined to be significant for adverse aesthetic impacts.

Air Quality

Since construction and operational emissions would occur concurrently, the emissions from both activities were evaluated together. The resulting emissions were compared to SCAQMD operational criteria pollutant thresholds. The worst-case criteria emissions would occur if all biogas facility operators chose to replace ICEs with gas turbines. In this scenario, PAR 1110.2 would reduce 4,311 pounds of NOx per day, 46,868 pounds of CO per day, 1,995 pounds of VOC per day and 13 pounds of SOx per day. PM10 would increase by 142 pounds per day and PM2.5 would increase by 142 pounds per day. The PM10 increase would be below the significance threshold of 150 pounds per day. The PM2.5 emissions would be greater than the significance threshold of 55 pounds per day. Therefore, PAR 1110.2 would be significant for PM2.5 operational emissions.

Hazards and Hazardous Materials

SCR systems require either urea or ammonia to control NOx. Use of urea would not result in offsite adverse impacts because it is not a hazardous material. Because of the hazards associated with anhydrous ammonia, an acutely hazardous material, SCAQMD policy precludes its use as a means of reducing NOx emissions. To further reduce hazards associated with ammonia, a permit condition that limits the aqueous ammonia concentration to 19 percent or less is typically required. Since 20 percent aqueous ammonia is evaluated by RMPComp (20 percent is the lowest concentration available in RMPComp), adverse impacts from aqueous ammonia were evaluated based on the 20 percent aqueous ammonia in the EA. The NOP/IS determined that adverse impacts from transport of aqueous ammonia would be less than significant, so transport of ammonia was not evaluated further in the Draft EA. SCAQMD staff estimated that the largest aqueous ammonia tank would be 5,000 gallons. Storage and use of aqueous ammonia, however, would generate potentially significant adverse impacts and, therefore, were evaluated in the Draft EA. The toxic endpoint for a 5,000 gallon aqueous ammonia tank would be 0.1 mile. Based on a survey of biogas facilities, some facilities have receptors within 0.1 mile of the existing ICEs. Since it is assumed that aqueous ammonia tanks for SCR system would need to be relatively near to the existing ICEs, it is assumed that the toxic endpoint for aqueous ammonia from a catastrophic failure of the storage tank would significantly adversely affect the receptors within 0.1 mile of the ICEs. Therefore, PAR 1110.2 has the potential to generate significant adverse hazardous impacts in the event of an accidental release of aqueous ammonia.

Installation of biogas to LNG plants instead of complying with PAR 1110.2 would include LNG storage tanks. Based on the SCAQMD's survey of facilities, and design of the LNG facility at the Bowerman Landfill, the largest LNG tank was estimated to be 71,000 gallons. The overpressure from a catastrophic release of 71,000 gallons of LNG with a berm was estimated to be 0.2 mile. Based on a survey of biogas facilities, some facilities have receptors with 0.1 miles of the existing ICEs. Therefore, PAR 1110.2 has the potential to generate signification adverse hazards impacts in the event of a catastrophic failure of an LNG storage tank.

Four accidental release scenarios were identified for the transport of LNG: release of LNG into a pool that evaporates and disperses without ignition; the ignition of a flammable cloud; a boiling liquid expanding vapor explosion (BLEVE) occurs; or the tank ruptures, rockets away and ignites. The worst-case endpoint from these scenarios is 0.3 mile from a vapor cloud fire, BLEVE or where a rocketing tank would land. Assuming that these accidents would occur near receptors, PAR 1110.2 has the potential to generate significant adverse hazard impacts in the event of an accidental release of LNG during transport.

FINDINGS

Public Resources Code §21081 and CEQA Guidelines §15091(a) state that no public agency shall approve or carry out a project for which a CEQA document has been completed which identifies one or more significant adverse environmental effects of the project unless the public agency makes one or more written findings for each of those significant effects, accompanied by a brief explanation of the rationale for each finding. Additionally, the findings must be supported by substantial evidence in the record (CEQA Guidelines §15091(b)). As identified in the Final EA and summarized above, the proposed project has the potential to create significant adverse aesthetics, construction air quality, and hazard and hazardous materials impacts. The SCAQMD Governing Board, therefore, makes the following findings regarding the proposed project. The findings are supported by substantial evidence in the record as explained in each finding. This Statement of Findings will be included in the record of project approval and will also be noted in the Notice of Decision.

1. **Potential aesthetic adverse impacts cannot be mitigated to insignificance.**

Finding and Explanation: Significant adverse aesthetic impacts are expected as a result of complying with PAR 1110.2 at biogas facilities. No specific mitigation measures were identified that could reduce significant adverse aesthetic impacts to less than significant. It is expected that facility operators would place control technology or ICE alternatives away from property boundaries. However, space issues and the location of utilities, location and quality of the biogas source, and piping may dictate the placement of equipment. Equipment may be masked by perimeter walls or landscape vegetation; although, fire prevention and safety issues would take precedence over aesthetic concerns. As a result, there is no guarantee that landscape vegetation would be available as a means of reducing aesthetics impacts.

Since the location and type of control equipment or ICE replacement is unknown for any specific biogas facility and the effectiveness of perimeter walls and landscaping to minimize aesthetics impacts is unknown, it is assumed that aesthetics impacts cannot be mitigated to less than significant.

The Governing Board finds that no feasible mitigation measures have been identified. CEQA Guidelines §15364 defines "feasible" as "capable of being accomplished in a successful manner within a reasonable period of time, taking into account economic, environmental, legal, social, and technological factors."

2. **Potential PM2.5 emissions from the gas turbine compliance option cannot be mitigated to insignificance.**

Finding and Explanation: PM2.5 emissions under the gas turbine compliance option were concluded to be significant in certain years. Secondary PM2.5 emissions under this compliance scenario are generated from the following sources: emergency diesel backup generators during periodic testing, diesel trucks transporting materials, e.g., catalyst, activated carbon, etc., to and from affected facilities, power plant emissions, etc. would occur. Based on the gas turbine biogas compliance option, PAR 1110.2 has the potential to emit 142 pounds of PM2.5 per day in some future years.

New gas turbines installed as a compliance option instead of complying with PAR 1110.2 would likely be subject to Rule 1303 or Rule 2005 BACT requirements. No add-on control technology or alternatives have been identified to reduce PM2.5 emissions from the gas turbine compliance option.

The Governing Board finds that no feasible mitigation measures have been identified to reduce significant adverse PM2.5 impacts under the gas turbine compliance option. CEQA Guidelines §15364 defines "feasible" as "capable of being accomplished in a successful manner within a reasonable period of time, taking into account economic, environmental, legal, social, and technological factors."

3. **Potential adverse hazard impacts from an accidental release of ammonia during storage and LNG during transport and storage that cannot be mitigated to insignificance.**

Finding and Explanation: In the event of a catastrophic release of aqueous ammonia from ammonia storage tanks, it was estimated that there could be exposure to concentrations of ammonia above the ERPG 2 level of 150 ppm within 0.1 mile of the storage tank. Due to the size and locations of affected facilities sensitive receptors are expected to be within 0.1 mile of the storage tank. Therefore PAR 1110.2 would be significant for accidental release from ammonia storage.

Under the alternative compliance option where the owner of an affected biogas engine replaces the engine with a biogas-to-LNG facility, significant adverse hazard impacts could occur under the following scenarios. The one psi overpressure from the cataclysmic destruction of the LNG storage tank is expected to extend 0.2 mile from the LNG storage tank. Due to the size and locations of affected facilities sensitive receptors are expected to be within 0.1 mile of the storage tank. Therefore PAR 1110.2 would be significant for accidental release from an on-site LNG storage tank. During transportation of LNG, it was estimated that adverse impacts from various releases would extend 0.3 mile. It is expected that sensitive receptors could be within 0.3 mile of roadway used by LNG trucks associated with PAR 1110.2. Therefore, PAR 1110.2 has the potential to generate significant hazard impacts associated with an accidental release of LNG during transport.

SCAQMD policy relative to air pollution control technologies requires the use of aqueous ammonia instead of anhydrous ammonia reduces potential adverse impacts in the event of an accidental release of ammonia used for SCR units. The use of 19 percent aqueous ammonia further reduces adverse impacts from in the event of an accidental release of ammonia.

Secondary containment (e.g. berms), valves that fail shut, emergency release values and barriers around ammonia or LNG storage tanks are design measures that are used to prevent the physical damage to storage tanks or limit the release of aqueous ammonia or LNG from storage tanks are typically required by local fire departments. Integrity testing of aqueous ammonia and LNG storage tanks assists in preventing failure from structural problems. Further, as part of the proposed project, SCAQMD staff will require that affected facility operators construct a containment system to be used during ammonia off-loading and LNG loading operations.

However, no additional mitigation measures beyond those identified above were identified that would reduce the hazard and hazardous material impacts from ammonia or LNG to less than significant. Therefore, the remaining hazards and hazardous material impacts from exposure to the ERPG 2 level of 150 ppm for ammonia and the one psi overpressure from the cataclysmic destruction of the LNG storage tank are considered to be significant.

The Governing Board finds that no additional feasible mitigation measures beyond those identified in the EA have been identified that can reduce adverse hazards and hazardous material impacts to less than significant. CEQA Guidelines §15364 defines "feasible" as "capable of being accomplished in a successful manner within a reasonable period of time, taking into account economic, environmental, legal, social, and technological factors."

4. **Feasible Alternatives to the Proposed Project do not reduce adverse aesthetic, air quality and hazards, and hazardous material impacts to insignificance.**

Finding and Explanation: The Governing Board finds further that in addition to the No Project Alternative, the Final EA considered alternatives pursuant to CEQA Guidelines §15126.6. Of all the alternatives considered, only Alternative C (Enhanced Enforcement) would reduce to insignificant levels the significant adverse aesthetic, air quality, and hazard and hazardous material impacts identified for the proposed project. Installation of CEMs, additional monitoring, etc., are not expected to change the visual character of the facility or surroundings and, therefore, would not be expected to generate significant adverse aesthetic impacts. Additional compliance requirements would not generate significant adverse construction or operational air quality impacts. Air toxics would be generated from source testing vehicle trips, but health risk from a single trip every other year would be negligible. Because Alternative C does not impose further emission control requirements, no facility operators would implement emission compliance options that could generate significant hazards/hazardous material impacts, because hazards would not be generated from increased monitoring and source testing. By not requiring any additional control equipment, facility operators are not expected to replace ICEs with ICE alternatives. The ICE alternatives were determined to be the source of adverse aesthetic, air quality and hazards and hazardous material impacts. However, while Alternative C would not generate significant adverse impacts compared to the proposed project, it would also not achieve most of the project objectives such as implementing the 2007 AQMP Control Measure MCS-01 – Facility Modernization; partially implementing SB 1298; and achieving further NOx, VOC, and PM emission reductions from affected engines.

Alternative B would extend and increase the low-use exception to non-biogas engines and extend the 15 minute averaging time during compliance testing to one hour. Impacts from implementing Alternative B would generally be similar to PAR 1110.2 because the greatest impacts occur from the various compliance options for biogas engines. Compliance options are essentially the same for both Alternative B and PAR 1110.2. Alternative B may generate lower construction emissions overall compared to PAR 1110.2, but because major construction activities are anticipated to occur at biogas facilities the maximum daily construction emissions may not be substantially different from those identified for PAR 1110.2. CO_2 emission reductions would be similar to CO_2 emission reductions identified for PAR 1110.2 because it is expected that replacing non-biogas ICEs with electric motors will be a less costly compliance option for the same categories of ICEs affected by both PAR 1110.2 and Alternative B. Aesthetic and hazards/hazardous material impacts are expected to be similar to PAR 1110.2 and, therefore, significant.

Alternative D is expected to generate significant adverse environmental impacts similar to those identified for PAR 1110.2. Alternative D may incrementally increase adverse environmental impacts because larger or additional control may be required to meet the lower CO compliance concentration limits. CO2 emission reductions would occur through the mandatory replacement of non-biogas engines with electric motors for categories for categories of engines where this compliance option is less costly than complying with the emission control requirements. While in practice Alternative D could generate greater adverse environmental impacts, the assumptions applied to PAR 1110.2 would also apply to Alternative D because these assumptions provide the most conservative analysis possible. Therefore, for this analysis the adverse environmental impacts from PAR 1110.2 and Alternative D are equivalent. Alternative D would be expected to create significant adverse aesthetics, air quality, and hazards/hazardous waste.

Although Alternative A-No Project Alternative, would not generate any of the adverse impacts identified for the proposed project, it would also not achieve any of the project objectives. An important objective of the proposed project is to improve an enhance compliance with the rule requirements. Under Alternative A it is possible that violations of Rule 1110.2 could continue to occur, albeit at a lower level than is currently the case because the SCAQMD is aware of compliance issues. Finally, Alternative A would not address SIP approvability issues identified by EPA.

No additional feasible mitigation measures or project alternatives, other than those already included in the Final EA, have been identified that can further mitigate the potentially significant project-specific impacts on air quality.

The SCAQMD finds that the proposed project achieves the best balance between emission reductions and the adverse aesthetic, air quality, and hazardous and hazardous material impacts due to construction and operation activities while meeting the objectives of the project. The SCAQMD further finds that all of the findings presented in this "Statement of Findings" are supported by substantial evidence in the record.

The record of approval for this project may be found in the SCAQMD's Clerk of the Board's Office located at SCAQMD Headquarters in Diamond Bar, California.

STATEMENT OF OVERRIDING CONSIDERATIONS

If significant adverse impacts of a proposed project remain after incorporating mitigation measures, or no measures or alternatives to mitigate the adverse impacts to less than significant levels are identified, the lead agency must make a determination that the benefits of the project outweigh the unavoidable adverse environmental effects if it is to approve the project. CEQA requires the decision-making agency to balance, as applicable, the economic, legal, social, technological, or other benefits of a proposed project against its unavoidable environmental risks when determining whether to approve the project (CEQA Guidelines §15093(a)). If the specific economic, legal, social, technological, or other benefits of a proposed project outweigh the unavoidable adverse environmental effects, the adverse environmental effects may be considered "acceptable" (CEQA Guidelines §15093(a)). Accordingly, a Statement of Overriding Considerations regarding potentially significant adverse impacts resulting from the proposed project has been prepared. This Statement of Overriding Considerations is included as part of the record of the project approval for the proposed project. Pursuant to CEQA Guidelines §15093(c), the Statement of Overriding Considerations will also be noted in the Notice of Decision for the proposed project.

Despite the inability to incorporate changes into the project that will mitigate potentially significant adverse impacts to a level of insignificance, the SCAQMD's Governing Board finds that the following benefits and considerations outweigh the significant unavoidable adverse environmental impacts:

1. The analysis of potential adverse environmental impacts incorporates a "worst-case" approach. This entails the premise that whenever the analysis requires that assumptions be made, those assumptions that result in the greatest adverse impacts are typically chosen. This method likely overestimates the actual adverse aesthetic, air quality, and hazards and hazardous material impacts resulting from the proposed project.

2. The proposed project implements, in part, AQMP control measure MSC-01. The long-term effect of PAR 1110.2, other SCAQMD rules, and AQMP control measures is the reduction of criteria emissions district-wide, contributing to attaining and maintaining the state and federal ambient air quality standards with a margin of safety. Beginning in 2008, PAR 1110.2 would reduce NOx emissions by 37 tons per year (204 pounds per day) CO emissions by 69 tons per year (379 pounds per day) and VOC emission by six tons per year (35 pounds per day). At full implementation, the long-term effect of the proposed amendments is a permanent reduction of NOx emissions by 4,335 tons per year (791 pounds per day), CO emissions by 38,845 tons per year (7,089 pounds per day) and VOC emission by 1,372 tons per year (250 pounds per day).

3. Although significant health risk impacts from diesel exhaust particulate emissions was identified, a mitigation measure was identified to reduce emissions impacts to a level of insignificance.

4. The proposed project and alternatives do not prescribe the means of controlling NOx, VOC and CO emissions. Facility operators may choose technologies that would not generate significant adverse aesthetic, air quality, or hazards and hazardous material impacts. For example, if biogas facility operators replaced their existing ICEs with microturbines or fuel cells, then there would not be any aesthetic, air quality, or hazards and hazardous material impacts.

5. The proposed project includes a technology assessment in 2010. The results of the technology assessment may result in identifying control technologies that would not generate significant adverse aesthetic, air quality, or hazards and hazardous material impacts.

6. The proposed project is expected to result in a net reduction of CO2 emissions based on the expectation that it will be more cost effective for operators of some types of non-

biogas engines to replace their engines with electric motors. As a worst-case assumption, PAR 1110.2 is expected to result in no net increase in CO_2 emissions.

7. One of the objectives of PAR 1110.2 is to address the four issues identified by EPA that were cause for disapproval of Rule 1110.2, which means it cannot be incorporated into the State Implementation Plan. Adopting PAR 1110.2 would correct the four issues identified by EPA.

The SCAQMD's Governing Board finds that the above-described considerations outweigh the unavoidable significant effects to the environment as a result of the proposed project.

MITIGATION MONITORING PLAN

CEQA requires an agency to prepare a plan for reporting and monitoring compliance with the implementation of measures to mitigate significant adverse environmental impacts. Mitigation monitoring requirements are included in CEQA Guidelines §15097 and Public Resources Code §21081.6, which specifically state:

When making findings as required by subdivision (a) of Public Resources Code §21081 or when adopting a negative declaration pursuant to paragraph (2) of subdivision (c) of Public Resources Code §21080, the public agency shall adopt a reporting or monitoring program for the changes to the project which it has adopted or made a condition of project approval in order to mitigate or avoid significant effects on the environment (Public Resources Code §21081.6). The reporting or monitoring program shall be designed to ensure compliance during project implementation. For those changes which have been required or incorporated into the project at the request of an agency having jurisdiction by law over natural resources affected by the project, that agency shall, if so requested by the lead or responsible agency, prepare and submit a proposed reporting or monitoring program.

The provisions of CEQA Guidelines §15097 and Public Resources Code §21081.6 are triggered when the lead agency certifies a CEQA document in which mitigation measures, changes, or alterations have been required or incorporated into the project to avoid or lessen the significance of adverse impacts identified in the CEQA document. Public Resources Code §21081.6 leaves the task of designing a reporting or monitoring plan to individual public agencies.

To fulfill the requirements of CEQA Guidelines §15097 and Public Resources Code §21081.6, the SCAQMD must develop a plan to monitor project compliance with those mitigation measures adopted as conditions of approval of the Final EA for the PAR 1110.2. The following subsections identify the specific mitigation measures identified in the Final EA and the public agency responsible for monitoring implementation of each mitigation measure.

Air Quality Impact

IMPACT SUMMARY OF MITIGATION MEASURES A-1: If a facility operator chooses to replace ICEs with alternative technologies, diesel emergency engines may be required as emergency backup engines in the event of an emergency. The analysis concluded that emissions from emergency engine testing could generate significant adverse cancer risk impacts. In the air quality analysis, it was determined that diesel particulate filters would reduce the carcinogenic health risks associated with diesel particulate emissions from the emergency engines to less than significant.

MITIGATION MEASURES:

Diesel Emergency Engines

A-1 Require particulate filters for any diesel emergency engine installed that generates a carcinogenic health risk greater than 10 in one million as a result of replacing existing ICEs at a facility as part of an alternative method of complying with PAR 1110.2.

IMPLEMENTING PARTIES: The SCAQMD's Governing Board finds that implementing the mitigation measures A-1 is the responsibility of the owner, operator, or agent of each affected facility who submits a permit application for emergency engines as a result of replacing existing ICEs to avoid compliance with the proposed project.

MONITORING AGENCY: The SCAQMD's Governing Board finds that through its discretionary authority to issue and enforce permits for this project, the SCAQMD will ensure compliance with mitigation measures A-1.

Hazard and Hazardous Material Impact

IMPACT SUMMARY OF MITIGATION MEASURES H-1: Facility operators who install ammonia or LNG storage tanks may generate a significant impact off-site in the event of an accidental release. Secondary containment of ammonia and LNG storage tanks are required by local fire departments. SCAQMD staff proposes that affected facilities construct a secondary containment system to be used during off-loading of ammonia and loading of LNG to further reduce off-site exposures in the event of an accidental release. No other mitigation to reduce the adverse impacts from off-site because of an accidental release of LNG or ammonia to less than significant was identified.

MITIGATION MEASURES:

Diesel Emergency Engines

H-1 Require secondary containment to be used during ammonia off-loading operations and LNG loading operations for any facility that has the potential to generate an off-site significant adverse impact in the event of an accidental release from ammonia or LNG storage tanks.

IMPLEMENTING PARTIES: The SCAQMD's Governing Board finds that implementing the mitigation measures H-1 is the responsibility of the owner, operator, or agent of each affected facility who submits a permit application for ammonia or LNG storage in connection with an alternative means of complying with the proposed project where it can be shown that the facility has the potential to generate significant adverse off-site hazard impacts because of an accidental release.

MONITORING AGENCY: The SCAQMD's Governing Board finds that through its discretionary authority to issue and enforce permits for this project, the SCAQMD will ensure compliance with mitigation measures H-1.

CONCLUSION

Based on a "worst-case" analysis, the potential adverse aesthetic, air quality, hazard and hazardous materials impacts from the adoption and implementation of PAR 1110.2 are considered significant and unavoidable. Construction of ICE alternatives may adversely impact the visual character of the area around affected facilities. Facility operators who choose to replace existing biogas ICES with gas turbines as an alternative to complying with the requirements of PAR 1110.2 may generate PM2.5 emissions that exceed the applicable regional significance threshold. Facility operators who replace existing ICEs may require diesel emergency engines. Diesel particulate filters were identified as a feasible mitigation measure that would reduce health risk from diesel emergency engine exhaust to less than significant. Facility operators who install ammonia or LNG tanks in connection with alternative compliance options have the potential to generate significant adverse hazard impacts in the event of an accidental release of either material. In addition to secondary containment features require by local fire departments for storage tanks, secondary containment around loading and off-loading operations would reduce adverse impacts, but would not reduce them to insignificance.

It is likely that existing SCAQMD Rule 1470 would already require diesel emergency back-up engines to be retrofitted with particulate filters or meet very low PM emission requirements. However, for any diesel emergency back-up engines that are installed as a result of adopting and implementing PAR 1110.2 and that may not be subject to Rule 1470, diesel particulate filters will be required to ensure that the engines do not generate significant adverse carcinogenic health risks.

No other feasible mitigation measures or project alternatives have been identified that would further reduce aesthetic, air quality, and hazards and hazardous material impacts to less than significant levels, while still achieving the overall objectives of the project.

(Adopted August 3, 1990)(Amended September 7, 1990)(Amended August 12, 1994)
(Amended December 9, 1994)(Amended November 14, 1997)
(Amended June 3, 2005)(Amended February 1, 2008)(Amended July 9, 2010)
(September 7, 2012)

Proposed Amended RULE 1110.2 EMISSIONS FROM GASEOUS- AND LIQUID-FUELED ENGINES

(a) Purpose

The purpose of Rule 1110.2 is to reduce Oxides of Nitrogen (NO_x), Volatile Organic Compounds (VOCs), and Carbon Monoxide (CO) from engines.

(b) Applicability

All stationary and portable engines over 50 rated brake horsepower (bhp) are subject to this rule.

(c) Definitions

For the purpose of this rule, the following definitions shall apply:

(1) AGRICULTURAL STATIONARY ENGINE is a non-portable engine used for the growing and harvesting of crops or the raising of fowl or animals for the primary purpose of making a profit, providing a livelihood, or conducting agricultural research or instruction by an educational institution. An engine used for the processing or distribution of crops or fowl or animals is not an agricultural engine.

(2) APPROVED EMISSION CONTROL PLAN is a control plan, submitted on or before December 31, 1992, and approved by the Executive Officer prior to November 14, 1997, that was required by subdivision (d) of this rule as amended September 7, 1990.

~~(3) BIOGAS CLEANUP SYSTEM is a system designed to remove siloxanes and other contaminants from raw landfill or digester gas (biogas). It is used for the protection of biogas engines and post-combustion (oxidation and selective catalytic reduction) catalysts.~~

(3~~4~~~~3~~) CERTIFIED SPARK-IGNITION ENGINES mean engines certified by California Air Resources Board (CARB) to meet emission standards in accordance with Title 13, Chapter 9, Article 4.5 of the California Code of Regulations (CCR).

(4~~5~~4) EMERGENCY STANDBY ENGINE is an engine which operates as a temporary replacement for primary mechanical or electrical power during periods of fuel or energy shortage or while the primary power supply is under repair.

(5~~6~~5) ENGINE is any spark- or compression-ignited internal combustion engine, including engines used for control of VOCs, but not including engines used for self-propulsion.

(6~~7~~6) EXEMPT COMPOUNDS are defined in District Rule 102 - Definition of Terms.

(7~~8~~7) FACILITY means any source or group of sources or other air contaminant emitting activities which are located on one or more contiguous properties within the District, in actual physical contact or separated solely by a public roadway or other public right-of-way, and are owned or operated by the same person (or by persons under common control), or an outer continental shelf (OCS) source as determined in Section 55.2 of Title 40, Part 55 of the Code of Federal Regulations (40 CFR Part 55). Such above-described groups, if noncontiguous, but connected only by land carrying a pipeline, shall not be considered one facility. Sources or installations involved in crude oil and gas production in Southern California Coastal or OCS Waters and transport of such crude oil and gas in Southern California Coastal or OCS Waters shall be included in the same facility which is under the same ownership or use entitlement as the crude oil and gas production facility on-shore.

(8~~9~~8) LEAN-BURN ENGINE means an engine that operates with high levels of excess air and an exhaust oxygen concentration of greater than 4 percent.

(9~~10~~9) LOCATION means any single site at a building, structure, facility, or installation. For the purpose of this definition, a site is a space occupied or to be occupied by an engine. For engines which are brought to a facility to perform maintenance on equipment at its permanent or ordinary location, each maintenance site shall be a separate location.

(10~~1~~0) NET ELECTRICAL ENERGY means the electrical energy produced by a generator, less the electrical energy consumed by any auxiliary equipment necessary to operate the engine generator and, if applicable, any heat recovery equipment, such as heat exchangers.

(11~~2~~1) NON-ROAD ENGINE is any engine, defined under 40 CFR Part 89, that does not remain or will not remain at a location for more than 12 consecutive months, or a shorter period of time where such period is representative of normal annual source operation at a stationary source that resides at a fixed location for more than 12 months (e.g., seasonal operations such as canning facilities), and meets one of the following:

(A) Is used in or on a piece of equipment that is self-propelled or serves a dual purpose by both propelling itself and performing another function (such as a mobile crane); or

(B) Is used in or on a piece of equipment that is intended to be propelled while performing its function (such as lawn mowers and string trimmers); or

(C) By itself, or in or on a piece of equipment, is portable or transportable, meaning designed to be and capable of being carried or moved from one location to another. Transportability includes, but is not limited to, wheels, skids, carrying handles, dolly, trailer, platform or mounting.

(12~~3~~2) OPERATING CYCLE means a period of time within which a round of regularly recurring events is completed, and cannot be stopped without the risk of endangering public safety or health, causing material damage to the equipment or product, or cannot be stopped due to technical constraints. Economic reasons alone will not be sufficient to extend this time period. The operating cycle includes batch processes that may start and finish several times within a twenty-four hour period, in which case each start to finish interval is considered a complete cycle.

(13~~4~~3) OXIDES OF NITROGEN (NOx) means nitric oxide and nitrogen dioxide.

(14~~5~~4) PORTABLE ENGINE is an engine that, by itself or in or on a piece of equipment, is designed to be and capable of being carried or moved from one location to another. Indications of portability include, but are not limited to, wheels, skids, carrying handles, dolly, trailer, platform or mounting. The operator must demonstrate the necessity of the engine being periodically moved from one location to another because of the nature of the operation.

An engine is not portable if:

(A) the engine or its replacement remains or will reside at the same location for more than 12 consecutive months. Any engine, such as a back-up or stand-by engine, that replaces an engine at a location and is intended to perform the same function as the engine being replaced, will be included in calculating the consecutive time period. In that case, the cumulative time of both engines, including the time between the removal of the original engine and installation of the replacement engine, will be counted toward the consecutive time period; or

(B) the engine remains or will reside at a location for less than 12 consecutive months where such a period represents the full length of normal annual source operations such as a seasonal source; or

(C) the engine is removed from one location for a period and then it or its equivalent is returned to the same location thereby circumventing the portable engine residence time requirements.

The period during which the engine is maintained at a designated storage facility shall be excluded from the residency time determination.

(15~~65~~) RATED BRAKE HORSEPOWER (bhp) is the rating specified by the manufacturer, without regard to any derating, and listed on the engine nameplate.

(16~~76~~) RICH-BURN ENGINE WITH A THREE-WAY CATALYST means an engine designed to operate near stoichiometric conditions with a catalytic control device that simultaneously reduces emissions of NOx, CO and VOC.

(17~~87~~) STATIONARY ENGINE is an engine which is either attached to a foundation or if not so attached, does not meet the definition of a portable or non-road engine and is not a motor vehicle as defined in Section 415 of the California Vehicle Code.

(18~~98~~) TIER 2 AND TIER 3 DIESEL ENGINES mean engines certified by CARB to meet Tier 2 or Tier 3 emission standards in accordance with Title 13, Chapter 9, Article 4 of the CCR.

(19~~2019~~) USEFUL HEAT RECOVERED means the waste heat recovered from the engine exhaust and/or cooling system that is put to productive use. The waste heat recovered may be~~y~~ assumed to be 100% useful unless the hot water, steam or other medium is vented to the atmosphere, or sent directly to a cooling tower or other unproductive use.

(20~~10~~) VOLATILE ORGANIC COMPOUND (VOC) is as defined in Rule 102.

(d) Requirements

(1) Stationary Engines:

(A) Operators of stationary engines with an amended Rule 1110.1 Emission Control Plan submitted by July 1, 1991, or an Approved Emission Control Plan, designating the permanent removal of engines or the replacement of engines with electric motors, in accordance with subparagraph (d)(1)(B), shall do so by December 31, 1999, or not operate the engines on or after December 31, 1999 in a manner that exceeds the emission concentration limits listed in Table I:

TABLE I ALTERNATIVE TO ELECTRIFICATION CONCENTRATION LIMITS		
NO_x	VOC	CO
(ppmvd)[1]	(ppmvd)[2]	(ppmvd)[1]
11	30	70

[1] Parts per million by volume, corrected to 15% oxygen on a dry basis and averaged over 15 minutes.

[2] Parts per million by volume, measured as carbon, corrected to 15% oxygen on a dry basis and averaged over the sampling time required by the test method.

(B) The operator of any ~~other~~ stationary engine not covered by (d)(1)(A) and not exempt from~~subject to~~ this rule shall

(i) Remove such engine permanently from service or replace the engine with an electric motor, or

(ii) Not operate the engine in a manner that exceeds the applicable emission concentration limits listed in either Table II or Table III-A or B.

TABLE II CONCENTRATION LIMITS		
NO_x (ppmvd)[1]	VOC (ppmvd)[2]	CO (ppmvd)[1]
bhp ≥ 500: 36 bhp < 500: 45	250	2000
CONCENTRATION LIMITS EFFECTIVE JULY 1, 2010		
NO_x (ppmvd)[1]	VOC (ppmvd)[2]	CO (ppmvd)[1]
bhp ≥ 500: 11 bhp < 500: 45	bhp ≥ 500: 30 bhp < 500: 250	bhp ≥ 500: 250 bhp < 500: 2000

CONCENTRATION LIMITS EFFECTIVE JULY 1, 2011		
NO_x (ppmvd)[1]	VOC (ppmvd)[2]	CO (ppmvd)[1]
11	30	250

[1] Parts per million by volume, corrected to 15% oxygen on a dry basis and averaged over 15 minutes.

[2] Parts per million by volume, measured as carbon, corrected to 15% oxygen on a dry basis and averaged over the sampling time required by the test method.

The concentration limits effective on and after July 1, 2010 shall not apply to engines that operate less than 500 hours per year or use less than 1 x 10^9 British Thermal Units (Btus) per year (higher heating value) of fuel.

If the operator of a two-stroke engine equipped with an oxidation catalyst and insulated exhaust ducts and catalyst housing demonstrates that the CO and VOC limits effective on and after July 1, 2010 are not achievable, then the Executive Officer may, with United States Environmental Protection Agency (EPA) approval, establish technologically achievable, case-by-case CO and VOC limits in place of the concentration limits effective on and after July 1, 2010. The case-by-case limits shall not exceed 250 ppmvd VOC and 2000 ppmvd CO.

If the operator of an engine that uses non-pipeline quality natural gas demonstrates that due to the varying heating value of the gas a longer averaging time is necessary, the Executive Officer may establish for the engine a longer averaging time, not to exceed six hours, for any of the concentration limits of Table II. Non-pipeline quality natural gas is a gas that does not meet the gas specifications of the local gas utility and is not supplied to the local gas utility.

(C) ~~Notwithstanding the provisions in subparagraph (d)(1)(B), t~~The operator of any stationary engine fired by landfill or digeste~~o~~r gas (biogas) shall not operate the engine in a manner that exceeds the emission concentration limits of Table III-A, provided that the facility monthly average biogas usage by the biogas engines is 90% or more, based on the higher heating value of the fuels used. The calculation of the monthly facility biogas use percentage may exclude natural gas fired during: any electrical outage at the facility; a Stage 2 or higher electrical emergencies called by the California Independent System Operator Corporation; and when a sewage treatment plant activates an Emergency Operations Center or Incident Command System, as part of an emergency response plan, because of either high influent flows caused by precipitation or a disaster.

~~The concentration limits effective on and after July 1, 2012 shall become effective provided the Executive Officer conducts a technology assessment that confirms that the limits are achievable, and reports to the Governing Board by July 2010, at a regularly scheduled public meeting.~~

~~The concentration limits effective on and after July 1, 2014 shall not apply to engines that operate less than 500 hours per year or use less than 1 x 10^9 Btus per year (higher heating value) of fuel.~~

TABLE III-A CONCENTRATION LIMITS FOR LANDFILL AND DIGESTE~~O~~R GAS (BIOGAS)-FIRED ENGINES		
NO_x (ppmvd)[1]	VOC (ppmvd)[2]	CO (ppmvd)[1]
bhp ≥ 500: 36 x ECF[3] bhp < 500: 45 x ECF[3]	Landfill Gas: 40 Digeste~~o~~r Gas: 250 x ECF[3]	2000
TABLE III-B CONCENTRATION LIMITS EFFECTIVE JANUARY 1, 2016		
NOx (ppmvd)[1]	VOC (ppmvd)[2]	CO (ppmvd)[1]
11	30	250
~~**CONCENTRATION LIMITS EFFECTIVE JULY 1, 2012**~~		
~~NO_x (ppmvd)[1]~~	~~VOC (ppmvd)[2]~~	~~CO (ppmvd)[1]~~
~~11~~	~~30~~	~~250~~
~~***TABLE III-B CONCENTRATION LIMITS AND COMPLIANCE SCHEDULE FOR LANDFILL AND DIGESTER GAS (BIOGAS)-FIRED ENGINES***~~		
~~***Category***~~	~~***Limit***~~	~~***Unit (s) Shall be in Full Compliance on or before***~~
~~*First Engine or Biogas Cleanup System for entire Biogas engine fleet*~~	~~*NO_x (ppmvd)[1]: 11*~~ ~~*VOC (ppmvd)[2]: 30*~~ ~~*CO (ppmvd)[1]: 250*~~	~~*July 1, 2015*~~
~~*Remaining Engine(s)*~~		~~*July 1, 2016*~~

1 Parts per million by volume, corrected to 15% oxygen on a dry basis and averaged over 15 minutes.

2 Parts per million by volume, measured as carbon, corrected to 15% oxygen on a dry basis and averaged over the sampling time required by the test method.

3 ECF is the efficiency correction factor.

The ECF shall be 1.0 unless:

(i) The engine operator has measured the engine's net specific energy consumption (q_a), in compliance with ASME Performance Test Code PTC 17 -1973, at the average load of the engine; and

(ii) The ECF-corrected emission limit is made a condition of the engine's permit to operate.

The ECF is as follows:

$$ECF = \frac{9250 \text{ Btus/hp-hr}}{\text{Measured } q_a \text{ in Btus/hp-hr}}$$

Measured q_a shall be based on the lower heating value of the fuel. ECF shall not be less than 1.0.

The Executive Officer may approve the burning of more than 10% natural gas in a landfill or digeste~~o~~r gas-fired engine, when it is necessary, if: the only alternative to limiting natural gas to 10% would be shutting down the engine and flaring more landfill or digeste~~o~~r gas; or the engine requires more natural gas in order for a waste heat recovery boiler to provide enough thermal energy to operate a sewage treatment plant, and other boilers at the facility are unable to provide the necessary thermal energy.

~~Once an engine complies with concentration limits effective on and after July 1, 2012, there shall be no limit on the percentage of natural gas burned.~~

(D) Notwithstanding the provisions of subparagraph (d)(1)(B), the operator of any stationary engine fired by landfill or digeste~~o~~r gas (biogas) shall not operate the engine in a manner that exceeds the emission concentration limits of Table III.

(E) Biogas engine operators that establish to the satisfaction of the Executive Officer that they have complied with the emissions limits of Table III-B by January 1, 2015 will have their respective engine permit application fees refunded.

~~(E)~~(F) Once an engine complies with the concentration limits as specified in Table III-B, there shall be no limit on the percentage of natural gas burned.

~~(D)~~~~(F)~~(G) The concentration limits effective as specified in Table III-B shall not apply to engines that operate fewer than 500 hours per year or use less than 1 x 10^9 Btus per year (higher heating value) of fuel.

~~(F)~~~~(G)~~(H) An operator of a biogas engine may determine compliance with the NOx and/or CO limits of Table III-B by utilizing a longer averaging time as set forth below, provided the operator demonstrates through CEMS data that the engine is achieving a concentration at or below 9.9 ppmv for NOx and 225 ppmv for CO (if CO is elected for averaging), ~~(~~each corrected to 15% O_2~~)~~, over a 4 month time period. An operator may utilize a monthly fixed interval averaging time for the first 4 months of the retrofitted engine's operation and up to a 24~~12~~ hour fixed interval averaging time thereafter. For purposes of determining compliance using a longer averaging time:

(i) An operator shall not average data during one-minute periods in which the underlying equipment is not operated or when the CEMS is undergoing zero or calibration checks, cylinder gas audits, or routine maintenance in accordance with the provisions in Rules 218 and 218.1~~*periods of calibration or audit*~~.

(ii) Notwithstanding the requirements of Rules 218 and 218.1, for one-minute time periods where NOx and/or CO CEMS data are greater than 95 percent of the Rule 218.1 Full Scale Range while the underlying equipment is operating, an operator shall use substitute data. ~~For one-minute time periods where NOx and/or CO CEMS data do not meet the requirements of Rules 218 and 218.1 while the underlying equipment is operating, an operator shall use substitute data for the missing one-minute CEMS data.~~ A concentration equivalent to 3 times the NOx and/or CO emission limits in Table III-B (each corrected to 15% O2) shall be used as substitute data. ~~*An operator shall use substitute CEMS data for all other one-minute CEMS data when NOx and/or CO emissions data has not been obtained or recorded or*~~

~~*does not meet the requirements of Rules 218 and 218.1. A concentration of 36 ppmv for NOx and 2000 ppmv for CO (each corrected to 15% O_2) shall be used as substitute data.*~~

~~(iii) The provisions of clause (d)(1)(H)(ii) supersede those in Rule 218 (f)(3)(B).~~

(iii~~v~~) The intentional shutdown of a CEMS to circumvent the emission limits of Table III-B while the underlying equipment is in operation shall constitute a violation of this rule.

(iv) The averaging provisions of this subparagraph shall not apply to CEMS that are time shared by multiple biogas engines.

~~(I)~~~~*(H)*~~(I) The operator of any new engine subject to subparagraph (e)(1)(B) shall:

(i) Comply with the requirements of Best Available Control Technology in accordance with Regulation XIII if the engine requires a District permit; or

(ii) Not operate the engine in a manner that exceeds the emission concentration limits in Table I if the engine does not require a District permit.

~~(J)~~~~*(I)*~~(J) By February 1, 2009, the operator of a spark-ignited engine without a Rule 218-approved continuous emission monitoring system (CEMS) or a Regulation XX (RECLAIM)-approved CEMS shall equip and maintain the engine with an air-to-fuel ratio controller with an oxygen sensor and feedback control, or other equivalent technology approved by the Executive Officer, CARB and EPA.

~~*(K)*~~~~*(J)*~~(K) New Non-Emergency Electrical Generators

(i) All new non-emergency engines driving electrical-generators shall comply with the following emission standards:

TABLE IV EMISSION STANDARDS FOR NEW ELECTRICAL GENERATION ENGINES	
Pollutant	**Emission Standard (lbs/MW-hr)[1]**
NOx	0.070
CO	0.20
VOC	0.10[2]

1. The averaging time of the emission standards is 15 minutes for NOx and CO and the sampling time required by the test method for VOC, except as described in the following clause.
2. Mass emissions of VOC shall be calculated using a ratio of 16.04 pounds of VOC per lb-mole of carbon.

(ii) Engines subject to this subparagraph that produce combined heat and electrical power may include one megawatt-hour (MW-hr) for each 3.4 million Btus of useful heat recovered (MW_{th}-hr), in addition to each MW-hr of net electricity produced (MW_e-hr). The compliance of such engines shall be based on the following equation:

$$\frac{\text{Lbs}}{\text{MW-hr}} = \frac{\text{Lbs}}{\text{MW}_e\text{-hr}} \times \text{Electrical Energy Factor (EEF)}$$

Where:

Lbs/MW-hr = The calculated emissions that shall comply with the emission standards in Table IV

Lbs/MW_e-hr = The short-term engine emission limit in pounds per MW_e-hr of net electrical energy produced, averaged over 15 minutes. The engine shall comply with this limit at all times.

EEF = The annual MW_e-hrs of net electrical energy produced divided by the sum of annual MW_e-hrs plus annual MW_{th}-hrs of useful heat recovered. The engine operator shall demonstrate annually that the EEF is less than the value required for compliance.

(iii) For combined heat and power engines, the short-term emission limits in lbs/MW_e-hr and the maximum allowed annual EEF must be selected by operator and stated on the operating permit.

(iv) Notwithstanding Rule 2001, the requirements of this subparagraph shall apply to NOx emissions from new non-emergency engines driving electrical-generators subject to Regulation XX (RECLAIM).

(v) This subparagraph does not apply to: engines installed prior to February 1, 2008; engines issued a permit to construct prior to February 1, 2008 and installed within 12 months of the date of the permit to construct; engines for which an application is deemed complete by October 1, 2007; engines installed by an electric utility on Santa Catalina Island; engines installed at remote locations without access to natural gas and electric power; engines used to supply electrical power to ocean-going vessels while at berth, prior to January 1, 2014; or landfill or digeste~~o~~r gas-fired engines that meet the requirements of subparagraph (d)(1)(C).

(2) Portable Engines:

(A) The operator of any portable engine generator subject to this rule shall not use the portable generator for:

(i) Power production into the electric grid, except to maintain grid stability during an emergency event or other unforeseen event that affects grid stability; or

(ii) Primary or supplemental power to a building, facility, stationary source, or stationary equipment, except during unforeseen interruptions of electrical power from the serving utility, maintenance and repair operations, and remote operations where grid power is unavailable. For interruptions of electrical power, the operation of a portable generator shall not exceed the time of the actual interruption of power.

This subparagraph shall not apply to a portable generator that complies with emission concentration limits of Table I and the other requirements in this rule applicable to stationary engines.

(B) The operator of any portable diesel engine shall comply with the applicable requirements of the Subchapter 7.5 Airborne Toxic Control Measures for diesel particulate matter in Chapter 1, Division 3, Title 17 of the California Code of Regulations.

(C) The operator of any portable spark-ignited engine shall comply with the applicable requirements of the Large Spark Ignition Engine Fleet Requirements, Article 2, Chapter 15, Division 3, Title 13 of the California Code of Regulations.

(e) Compliance

(1) Agricultural Stationary Engines:

(A) The operator of any agricultural stationary engine subject to this rule and installed or issued a permit to construct prior to June 3, 2005 shall comply with subparagraph (d)(1)(B) and the other applicable provisions of this rule in accordance with the compliance schedules in Table V:

TABLE V
COMPLIANCE SCHEDULES FOR STATIONARY AGRICULTURAL ENGINES

Action Required	Tier 2 and Tier 3 Diesel Engines, Certified Spark-Ignition Engines, and All Engines at Facilities with Actual Emissions Less Than the Amounts in the Table of Rule 219(q)	Other Engines
Submit notification of applicability to the Executive Officer	January 1, 2006	January 1, 2006
Submit to the Executive Officer applications for permits to construct engine modifications, control equipment, or replacement engines	March 1, 2009	September 1, 2007

TABLE V COMPLIANCE SCHEDULES FOR STATIONARY AGRICULTURAL ENGINES		
Action Required	**Tier 2 and Tier 3 Diesel Engines, Certified Spark-Ignition Engines, and All Engines at Facilities with Actual Emissions Less Than the Amounts in the Table of Rule 219(q)**	**Other Engines**
Initiate construction of engine modifications, control equipment, or replacement engines	September 30, 2009, or 30 days after the permit to construct is issued, whichever is later	March 30, 2008, or 30 days after the permit to construct is issued, whichever is later
Complete construction and comply with applicable requirements	January 1, 2010, or 60 days after the permit to construct is issued, whichever is later	July 1, 2008, or 60 days after the permit to construct is issued, whichever is later
Complete initial source testing	March 1, 2010, or 120 days after the permit to construct is issued, whichever is later	September 1, 2008, or 120 days after the permit to construct is issued, whichever is later

The notification of applicability shall include the following for each engine:

(i) Name and mailing address of the operator

(ii) Address of the engine location

(iii) Manufacturer, model, serial number, and date of manufacture of the engine

(iv) Application number

(v) Engine type (diesel, rich-burn spark-ignition or lean-burn spark-ignition)

(vi) Engine fuel type

(vii) Engine use (pump, compressor, generator, or other)

(viii) Expected means of compliance (engine replacement, control equipment installation, or electrification)

(B) The operator of any new agricultural stationary engine that is not subject to the compliance schedule of subparagraph (e)(1)(A) for existing engines shall comply with the requirements of subparagraph (d)(1)(I~~HD~~) immediately upon installation.

(2) Non-Agricultural Stationary Engines:

(A) The operator of any stationary engine not meeting the requirements of subparagraphs (d)(1)(B) or (d)(1)(C) that go into effect in 2010 or later, shall comply with the compliance schedule in Table VI:

TABLE VI
COMPLIANCE SCHEDULE FOR NON -AGRICULTURAL STATIONARY ENGINES

Action Required	Applicable Compliance Date
Submit to the Executive Officer applications for permits to construct engine modifications, control equipment, or replacement engines	Twelve months before the final compliance date
Initiate construction of engine modifications, control equipment, or replacement engines	Three months before the final compliance date, or 60 days after the permit to construct is issued, whichever is later
Complete construction and comply with applicable requirements	The final compliance date, or 120 days after the permit to construct is issued, whichever is later
Complete initial source testing	60 days after the final compliance date in (d)(1)(B) or (d)(1)(C), or 180 days after the permit to construct is issued, whichever is later

(B) The operator of any stationary engine that elects to amend a permit to operate to incorporate ECF-adjusted emission limits shall submit to the Executive Officer an application for a change of permit conditions by August 1, 2008, and comply with emission limits of the previous version of this rule until February 1, 2009 when the engine shall be in compliance with the emission limits of this rule.

(C) The operator of any stationary engine that is required to add operating restrictions to a permit to operate to meet the requirements of this rule shall submit to the Executive Officer an application for a change of permit conditions by August 1, 2008.

(3) Stationary Engine CEMS

(A) The operator of any stationary engine with an existing CEMS shall commence the reporting required by Rule 218 Subdivision (f) on January 1, 2008. The first summary report for the six months ending June 30, 2008 shall be due on July 30, 2008.

(B) The operator of any stationary engine that is required to modify an existing CEMS or install a CEMS on an existing engine shall comply with the compliance schedule in Table VII. Public agencies shall be allowed one year more than the dates in Table VII, except for biogas engines.

TABLE VII
COMPLIANCE SCHEDULE FOR NEW OR MODIFIED CEMS ON EXISTING ENGINES

	Applicable Compliance Dates For:		
Action Required	**Non-Biogas Engines Rated at 750 bhp or More**	**Non-Biogas Engines Rated at Less than 750 bhp**	**Biogas Engines***
Submit to the Executive Officer applications for new or modified CEMS	August 1, 2008	August 1, 2009	January 1, 2011
Complete installation and commence CEMS operation, calibration, and reporting requirements	Within 180 days of initial approval	Within 180 days of initial approval	Within 180 days of initial approval
Complete certification tests	Within 90 days of installation	Within 90 days of installation	Within 90 days of installation
Submit certification reports to Executive Officer	Within 45 days after tests are completed	Within 45 days after tests are completed	Within 45 days after tests are completed
Obtain final approval of CEMS	Within 1 year of initial approval	Within 1 year of initial approval	Within 1 year of initial approval

* A biogas engine is one that is subject to the emission limits of Table III.

(4) Stationary Engine Inspection and Monitoring (I&M) Plans:

The operator of stationary engines subject to the I&M plan provisions of subparagraph (f)(1)(D) shall:

(A) By August 1, 2008, submit an initial I&M plan application to the Executive Officer for approval;

(B) By December 1, 2008, implement an approved I&M plan or the I&M plan as submitted if the plan is not yet approved.

Any operator of 15 or more stationary engines subject to the I&M plan provisions shall comply with the above schedule for at least 50% of engines, and for the remaining engines shall:

(C) By February 1, 2009, submit an initial I&M plan application to the Executive Officer for approval;

(D) By June 1, 2009, implement an approved I&M plan or the I&M plan as submitted if the plan is not yet approved.

(5) Stationary Engine Air-to-Fuel Ratio Controllers

(A) The operator of any stationary engine that does not have an air-to-fuel ratio controller, as required by subparagraph (d)(1)(J~~E~~), shall comply with those requirements in accordance with the compliance schedule in Table V~~I~~, except that the application due date is no later than May 1, 2008 and the initial source testing may be conducted at the time of the testing required by subparagraph (f)(1)(C).

(B) The operator of any stationary engine that has the air-to-fuel ratio controller required by subparagraph (d)(1)(J~~E~~), but it is not listed on the permit to operate, shall submit to the Executive Officer an application to amend the permit by April 1, 2008.

(C) The operator of more than five engines that do not have air-to-fuel ratio controllers may take an additional three months, to May 1, 2009, to install the equipment on up to 50% of the affected engines.

(6) New Stationary Engines

The operator of any new stationary engine issued a permit to construct after February 1, 2008 shall comply with the applicable I&M or CEMS requirements of this rule when operation commences. If applicable, the operator shall provide the required information in subparagraph (f)(1)(D) to the Executive Officer prior to the issuance of the permit to construct so that the I&M procedures can be included in the permit. A separate I&M plan application is not required.

(7) Biogas Engines

For any biogas engine for which the operator applies to the Executive Officer by April 1, 2008 for a change of permit conditions for ECF-corrected emission limits, or the approval to burn more than 10 percent natural gas in accordance with subparagraph (d)(1)(C~~EC~~), the biogas engine shall not be subject to the initial concentration limits of Tables II or III until August 1, 2008, provided the operator continues to comply with all emission limits in effect prior to February 1, 2008.

(8) Compliance Schedule Exception

If an engine operator submits to the Executive Officer an application for an administrative change of permit conditions to add a permit condition that causes the engine permit to expire by the effective date of any requirement of this rule, then the operator is not required to comply with the earlier steps required by this subdivision for that requirement. The effective date for the CEMS requirements shall be one year after the date that a CEMS application is due.

(9) Exceedance of Usage Limits

(A) If an engine was initially exempt from the new concentration limits in subparagraph (d)(1)(B) or subparagraph (d)(1)(C) that take effect on or after July 1, 2010 because of low engine use but later exceeds the low-use criteria, the operator shall bring the engine into compliance with the rule in accordance with the schedule in Table VI with the final compliance date in Table VI being twelve months after the conclusion of the first twelve-month period for which the engine exceeds the low-use criteria.

(B) If engines that were initially exempt from new CEMS by the low-use criterion in subclause (f)(1)(A)(ii)(I) later exceed that criterion, the operator shall install CEMS on those engines in accordance with the schedule in Table VII, except that the date for submitting the CEMS application in Table VII shall be six months after the conclusion of the first twelve-month period for which the engines exceed the criterion.

(f) Monitoring, Testing, Recordkeeping and Reporting

(1) Stationary engines:

The operator of any engine subject to the provisions of paragraph (d)(1) of this rule shall meet the following requirements:

(A) Continuous Emission Monitoring

(i) For engines of 1000 bhp and greater and operating more than two million bhp-hr per calendar year, a NO_x and CO continuous emission monitoring system (CEMS) shall be installed, operated and maintained in calibration to demonstrate compliance with the emission limits of this rule.

(ii) (I) For facilities with engines subject to paragraph (d)(1), having a combined rating of 1500 bhp or greater at the same location, and having a combined fuel usage of more than 16 x 10^9 Btus per year (higher heating value), CEMS shall be installed, operated and maintained in calibration to demonstrate compliance of those engines with the applicable NO_x and CO emission limits of this rule.

(II) Any engine that as of October 1, 2007 is located within 75 feet of another engine (measured from engine block to engine block) is considered to be at the same location. Operators of new engines shall not install engines farther than 75 feet from another engine unless the operator demonstrates to the Executive Officer that operational needs or space limitations require it.

(III) The following engines shall not be counted toward the combined rating or required to have a CEMS by this clause: engines rated at less than 500 bhp; standby engines that are limited by permit conditions to only operate when other primary engines are not operable; engines that are limited by permit conditions to operate less than 1000 hours per year or a fuel usage of less than 8 x 10^9 Btus per year (higher heating value of all fuels used); engines that are used primarily to fuel public natural gas transit vehicles and that are required by a permit condition to be irreversibly removed from service by December 31, 2014; and engines required to have a CEMS by the previous clause. A CEMS shall not be required if permit conditions limit the simultaneous use of the engines at the same location in a manner to limit the combined rating of all engines in simultaneous operation to less than 1500 bhp.

(IV) For engines rated below 1000 bhp, the CEMS may be time shared by multiple engines.

(V) Operation of engines by the electric utility in the Big Bear Lake area during the failure of a transmission line to the utility may be excluded from an hours-per-year or fuel usage limit that is elected by the operator pursuant to subclause (f)(1)(A)(ii)(III).

(VI) In lieu of complying with subclause (f)(1)(A)(ii)(I), an operator that is a public agency, or is contracted to operate engines solely for a public agency, may comply with the Inspection and Monitoring Plan requirements of subparagraph (f)(1)(D), except that the operator shall conduct emission checks at least weekly or every 150 operating hours, whichever occurs later. If any such engine is found to exceed an applicable NOx or CO limit by a source test required by subparagraph (f)(1)(C) or District test using a portable analyzer on three or more occasions in any 12-month period, the operator shall comply with the CEMS requirements of this subparagraph for such engine in accordance with the compliance schedule of Table VII, except that the operator shall submit a CEMS application to the

Executive Officer within six months of the third exceedance.

(iii) All CEMS required by this rule shall:

(I) Comply with the applicable requirements of Rule 218, including equipment specifications and certification, operating, recordkeeping, quality assurance and reporting requirements, except as otherwise authorized by this rule;

(II) Include equipment that measures and records exhaust gas concentrations, both uncorrected and corrected to 15 percent oxygen on a dry basis; and

(III) Have data gathering and retrieval capability approved by the Executive Officer

(iv) The operator of an engine that is required to install CEMS may request the Executive Officer to approve an alternative monitoring device (or system components) to demonstrate compliance with the emission limits of this rule. The applicant shall demonstrate to the Executive Officer that the proposed alternative monitoring device is at a minimum equivalent in relative accuracy, precision, reliability, and timeliness to a CEMS for that engine, according to the criteria specified in 40 CFR Part 75 Subpart E. In lieu of the criteria specified in 40 CFR Part 75 Subpart E, substitute criteria is acceptable if the applicant demonstrates to the Executive Officer that the proposed alternative monitoring device is at minimum equivalent in relative accuracy, precision, reliability, and timeliness to a CEMS for that engine. Upon approval by the Executive Officer, the substitute criteria shall be submitted to EPA as an amendment to the State Implementation Plan (SIP).

If the alternative monitoring device is denied or fails to be recertified, a CEMS shall be required.

(v) Notwithstanding the requirements of Rules 218 and 218.1, operators of engines that are required to install a CEMS by clause (f)(1)(A)(ii) of this subparagraph may:

(I) Store data electronically without a strip chart recorder, but there shall be redundant data storage capability for at least 15 days of data. The operator must demonstrate that both sets of data are equivalent.

(II) Conduct relative accuracy testing on the same schedule for source testing in clause (f)(1)(C)(i), instead of annually. The minimum sampling time for each test is 15 minutes.

(vi) Notwithstanding the requirements of Rules 218 and 218.1, operators of engines that are required to install a CEMS by clause (ii) of this subparagraph, and that are to be monitored by a timeshared CEMS, may:

(I) Monitor an engine with the CEMS for 15 consecutive minutes, purge for the minimum required purge time, then monitor the next engine for 15 consecutive minutes. The CEMS shall operate continuously in this manner, except for required calibrations.

(II) Record the corrected and uncorrected NOx, CO and diluent data at least once per minute and calculate and record the 15-minute average corrected concentrations for each sampling period.

(III) Have sample lines to each engine that are not the same length. The purge time will be based on the sample line with the longest response time. Response times shall be checked during cylinder gas audits. Sample lines shall not exceed 100 feet in length.

(IV) Conduct a minimum of five tests for each engine during relative accuracy tests.

(V) Perform a cylinder gas audit every calendar quarter on each engine, except for engines for which relative accuracy testing was conducted that quarter.

(VI) Exclude monitoring of nitrogen dioxide (NO_2) for rich-burn engines, unless source testing demonstrates that NO_2 is more than 10 percent of total NOx.

(VII) Conduct daily calibration error (CE) tests by injecting calibration gases at the analyzers, except that at least once per week the CE test shall be conducted by injecting calibration gases as close to the probe tip as practical.

(VIII) Stop operating and calibrating the CEMs during any period that the operator has a continuous record that the engine was not in operation.

(vii) A CO CEMS shall not be required for lean-burn engines or an engine that is subject to Regulation XX (RECLAIM), and not required to have a NOx CEMS by that regulation.

(viii) Notwithstanding the requirements of this paragraph and paragraph (c)(2) of Rule 2012, an operator may take an existing NOx CEMS out of service for up to two weeks (cumulative) in order to modify the CEMS to add CO monitoring.

(B) Elapsed Time Meter

Maintain an operational non-resettable totalizing time meter to determine the engine elapsed operating time.

(C) Source Testing

(i) Effective August 1, 2008, conduct source testing for NO_x, VOC reported as carbon, and CO concentrations (concentrations in ppm by volume, corrected to 15 percent oxygen on dry basis) at least once every two years, or every 8,760 operating hours, whichever occurs first. Relative accuracy tests required by Rule 218.1 or 40 CFR Part 75 Subpart E will satisfy this requirement for those pollutants monitored by a CEMS. The source test frequency may be reduced to once every three years if the engine has operated less than 2,000 hours since the last source test. If the engine has not been operated within three months of the date a source test is required, the source test shall be conducted when the engine resumes operation for a period longer than either seven consecutive days or 15 cumulative days of operation. The operator of the engine shall keep sufficient operating records to demonstrate that it meets the requirements for extension of the source testing deadlines.

(ii) Conduct source testing for at least 30 minutes during normal operation (actual duty cycle). This test shall not be conducted under a steady-state condition unless it is the normal operation. In addition, conduct source testing for NOx and CO emissions for at least 15 minutes at: an engine's actual peak load, or the maximum load that can be practically achieved during the test, and; at actual minimum load, excluding idle, or the minimum load that can be practically achieved during the test. These additional two tests are not required if the permit limits the engine to operating at one defined load, ± 10%. No pre-tests for compliance are permitted. The emission test shall be conducted at least 40 operating hours, or at least 1 week, after any engine servicing or tuning. If an emission exceedance is found during any of the three phases of the test, that phase shall be completed and reported. The operator shall correct the exceedance, and the source test may be immediately resumed.

(iii) Use a contractor to conduct the source testing that is approved by the Executive Officer under the Laboratory Approval Program for the necessary test methods.

(iv) Submit a source test protocol to the Executive Officer for written approval at least 60 days before the scheduled date of the test. The source test protocol shall include the name, address and phone number of the engine operator and a District-approved source testing contractor that will conduct the test, the application and permit number(s), emission limits, a description of the engine(s) to be tested, the test methods and procedures to be used, the number of tests to be conducted and under what loads, the required minimum sampling time for the VOC test, based on the analytical detection limit and expected VOC levels, and a description of the parameters to be measured in accordance with the I&M plan required by subparagraph (f)(1)(D). The source test protocol shall be approved by the Executive Officer prior to any testing. The operator is not required to submit a protocol for approval if: there is a previously approved protocol that meets these requirements; the engine has not been altered in a manner that requires a permit alteration; and emission limits have not changed since the previous test. If the operator submits the protocol by the required date, and the Executive Officer takes longer than 60 days to approve the protocol, the operator shall be allowed the additional time needed to conduct the test.

(v) Provide the Executive Officer at least 30 days prior notice of any source test to afford the Executive Officer the opportunity to have an observer present. If after 30 days notice for an initially scheduled performance test, there is a delay (due to operational problems, etc.) in conducting the scheduled performance test, the engine operator shall notify the Executive Officer as soon as possible of any delay in the original test date, either by providing at least seven days prior notice of the rescheduled date of the performance test, or by arranging a rescheduled date with the Executive Officer by mutual agreement.

(vi) Submit all source test reports, including a description of the equipment tested, to the Executive Officer within 60 days of completion of the test.

(vii) By February 1, 2009, provide, or cause to be provided, source testing facilities as follows:

(I) Sampling ports adequate for the applicable test methods. This includes constructing the air pollution control system and stack or duct such that pollutant concentrations can be accurately determined by applicable test methods;

(II) Safe sampling platform(s), scaffolding or mechanical lifts, including safe access, that comply with California General Safety Orders. Agricultural stationary engines are excused from this subclause if they are in remote locations without electrical power;

(III) Utilities for sampling and testing equipment. Agricultural stationary engines are exempt from this subclause if they are on wheels and moved to storage during the off season.

(D) Inspection and Monitoring (I&M) Plan

Submit to the Executive Officer for written approval and implement an I&M plan. One plan application is required for each facility. The I&M plan shall include:

(i) Identification of engine and control equipment operating parameters necessary to maintain pollutant concentrations within the rule and permit limits. This shall include, but not be limited to:

(I) Procedures for using a portable NOx, CO and oxygen analyzer to establish the set points of the air-to-fuel ratio controller (AFRC) at 25%, 60% and 95% load (or fuel flow rate), ± 5%, or the minimum, midpoint and maximum loads that actually occur during normal operation, ± 5%, or at any one load within the ± 10% range that an engine permit is limited to in accordance with clause (f)(1)(C)(ii);

(II) Procedures for verifying that the AFRC is controlling the engine to the set point during the daily monitoring required by clause (f)(1)(D)(iv);

(III) Procedures for reestablishing all AFRC set points with a portable NOx, CO and oxygen analyzer whenever a set point must be readjusted, within 24 hours of an oxygen sensor replacement, and, for rich-burn engines with three way catalysts, between 100 and 150 engine operating hours after an oxygen sensor replacement;

(IV) For engines with catalysts, the maximum allowed exhaust temperature at the catalyst inlet, based on catalyst manufacturer specifications;

(V) For lean-burn engines with selective catalytic control devices, the minimum exhaust temperature at the catalyst inlet required for reactant flow (ammonia or urea), and procedures for using a portable NOx and oxygen analyzer to establish the acceptable range of reactant flow rate, as a function of load.

Parameter monitoring is not required for diesel engines without exhaust gas recirculation and catalytic exhaust control devices.

(ii) Procedures for alerting the operator to emission control malfunctions. Engine control systems, such as air-to-fuel ratio controllers, shall have a malfunction indicator light and audible alarm.

(iii) Procedures for at least weekly or every 150 engine operating hours, whichever occurs later, emissions checks by a portable NOx, CO and oxygen analyzer.

(I) If an engine is in compliance for three consecutive emission checks, without any adjustments to the oxygen sensor set points, then the engine may be checked monthly or every 750 engine operating hours, whichever occurs later, until there is a noncompliant emission check or, for rich-burn engines with three-way catalysts, the oxygen sensor is replaced. When making adjustments to the oxygen sensor set points, returning to a more frequent emission check schedule is not required if the engine is in compliance with the applicable emission limits prior to and after the set point adjustments, notwithstanding the requirements of (f)(1)(D)(iii)(IV).

(II) For diesel engines and other lean-burn engines that are subject to Regulation XX or have a NOx CEMs, and that are subject to a CO limit more stringent than the 2000 ppmvd limit of Tables II or III, a CO emission check shall be performed at least quarterly, or every 2,000 engine operating hours, whichever occurs later.

(III) For diesel engines and other lean-burn engines that are subject to Regulation XX or have a NOx CEMs, and that are not subject to a CO limit more stringent than the 2000 ppmvd limit of Tables II or III, emission checks are not required.

(IV) No engine or control system maintenance or tuning may be conducted within 72 hours prior to the emission check, unless it is an unscheduled, required repair.

(V) The portable analyzer shall be calibrated, maintained and operated in accordance with the manufacturer's specifications and recommendations and the Protocol for the Periodic Monitoring of Nitrogen Oxides, Carbon Monoxide, and Oxygen from Stationary Engines Subject to South Coast Air Quality Management District Rule 1110.2, approved on February 1, 2008, or subsequent protocol approved by EPA and the Executive Officer.

(iv) Procedures for at least daily monitoring, inspection and recordkeeping of:

(I) engine load or fuel flow rate;

(II) the set points, maximums and acceptable ranges of the parameters identified by clause (f)(1)(D)(i), and the actual values of the same parameters;

(III) the engine elapsed time meter operating hours;

(IV) the operating hours since the last emission check required by clause (f)(1)(D)(iii);

(V) for rich-burn engines with three-way catalysts, the difference of the exhaust temperatures (ΔT) at the inlet and outlet of the catalyst (changes in the ΔT can indicate changes in the effectiveness of the catalyst);

(VI) engine control system and AFRC system faults or alarms that affect emissions.

The daily monitoring and recordkeeping may be done in person by the operator, or by remote monitoring.

(v) Procedures for responding to, diagnosing and correcting breakdowns, faults, malfunctions, alarms, emission checks finding emissions in excess of rule or permit limits, and parameters out-of-range.

(I) For a breakdown resulting in a violation of this rule or a permit condition, or for an emission check that finds emissions in excess of those allowed by this rule or a permit condition, the operator shall correct the problem and demonstrate compliance with another emission check, or shut down an engine by the end of an operating cycle, or within 24 hours from the time the operator knew of the breakdown or excess emissions, or reasonably should have known, whichever is sooner.

(II) For other problems, such as parameters out-of-range, an operator shall correct the problem and demonstrate compliance with another emission check within 48 hours of the operator first knowing of the problem.

(III) An operator shall not be considered in violation of the emission limits of this rule or in permit conditions if the operator complies with this subparagraph and the reporting requirements of subparagraph (f)(1)(H). Any emission check conducted by District staff that finds excess emissions is a violation.

(vi) Procedures and schedules for preventive and corrective maintenance.

(vii) Procedures for reporting noncompliance to the Executive Officer in accordance with subparagraph (f)(1)(H).

(viii) Procedures and format for the recordkeeping of monitoring and other actions required by the plan.

(ix) Procedures for plan revisions. Before any change in I&M plan operations can be implemented, the revised I&M plan shall be submitted to and approved by the Executive Officer. The operator shall apply for a plan revision prior to any change in emission limits or control equipment.

(x) An engine is not subject to this subparagraph if it is required by this rule to have a NOx and CO CEMS, or voluntarily has a NOx and CO CEMS that complies with this rule.

(E) Operating Log

Maintain a monthly engine operating log that includes:

(i) Total hours of operation;

(ii) Type of liquid and/or type of gaseous fuel;

(iii) Fuel consumption (cubic feet of gas and gallons of liquid); and

(iv) Cumulative hours of operation since the last source test required in subparagraph (f)(1)(C).

Facilities subject to Regulation XX may maintain a quarterly log for engines that are designated as a process unit on the facility permit.

(F) New Non-Emergency Electrical Generating Engines

Operators of engines subject to the requirements of subparagraph (d)(1)(K~~J~~) shall also meet the following requirements.

(i) The engine generator shall be monitored with a calibrated electric meter that measures the net electrical output of the engine generator system, which is the difference between the electrical output of the generator and the electricity consumed by the auxiliary equipment necessary to operate the engine generator.

(ii) For engines monitored with a CEMS, the emissions of the monitored pollutants in ppmvd corrected to 15% O2, lbs/hr, and lbs/MW_e-hr and the net MW_e-hrs produced shall be calculated and recorded for the four 15-minute periods of each hour of operation. The mass emissions of NOx shall be calculated based on the measured fuel flow and one of the F factor methods of 40 CFR 60, Appendix A, Method

19, or other method approved by the Executive Officer. Mass emissions of CO shall be calculated in the same manner as NOx, except that the ppmvd CO shall be converted to lb/scf using a conversion factor of 0.727 x 10^{-7}.

(iii) For NOx and CO emissions from engines not monitored with a CEMS and VOC emissions from all engines, the emissions of NOx, CO and VOC in lbs/MW_e-hr shall be calculated and recorded whenever the pollutant is measured by a source test or emission check. Mass emissions of NOx and CO shall be calculated in the same manner as the previous clause. Mass emissions of VOC shall be calculated in the same manner, except that the ppmvd VOC as carbon shall be converted to lb/scf using a conversion factor of 0.415 x 10^{-7}.

(iv) For engines generating combined heat and power that rely on the EEF to comply with Table IV emission standards, the daily and annual useful heat recovered (MW_{th}-hrs), net electrical energy generated (MW_e-hrs) and EEF shall be monitored and recorded.

(v) Other methods of calculating mass emissions than those specified, such as by direct measurement of exhaust volume, may be used if approved by the Executive Officer. All monitoring, calculation, and recordkeeping procedures must be approved by the Executive Officer.

(vi) Operators of combined heat and power engines shall submit to the Executive Officer the reports of the following information within 15 days of the end of the first year of operation, and thereafter within 15 days of the end of each calendar year: the annual net electrical energy generated (MW_e-hrs); the annual useful heat recovered (MW_{th}-hrs), the annual EEF calculated in accordance with clause (d)(1)(K~~JF~~)(ii); and the maximum annual EEF allowed by the operating permit. If the actual annual EEF exceeds the allowed EEF, the report shall also include the time periods and emissions for all instances where emissions exceeded any emission standard in Table IV.

(G) Portable Analyzer Operator Training

The portable analyzer tests required by the I&M Plan requirements of subparagraph (f)(1)(D) shall only be conducted by a person who has completed an appropriate District-approved training program in the operation of portable analyzers and has received a certification issued by the District.

(H) Reporting Requirements

(i) The operator shall report to the Executive Officer, by telephone (1-800-CUT-SMOG or 1-800-288-7664) or other District-approved method, any breakdown resulting in emissions in excess of rule or permit emission limits within one hour of such noncompliance or within one hour of the time the operator knew or reasonably should have known of its occurrence. Such report shall identify the time, specific location, equipment involved, responsible party to contact for further information, and to the extent known, the causes of the noncompliance, and the estimated time for repairs. In the case of emergencies that prevent a person from reporting all required information within the one-hour limit, the Executive Officer may extend the time for the reporting of required information provided the operator has notified the Executive Officer of the noncompliance within the one-hour limit.

(ii) Within seven calendar days after the reported breakdown has been corrected, but no later than thirty calendar days from the initial date of the breakdown, unless an extension has been approved in writing by the Executive Officer, the operator shall submit a written breakdown report to the Executive Officer which includes:

(I) An identification of the equipment involved in causing, or suspected of having caused, or having been affected by the breakdown;

(II) The duration of the breakdown;

(III) The date of correction and information demonstrating that compliance is achieved;

(IV) An identification of the types of excess emissions, if any, resulting from the breakdown;

(V) A quantification of the excess emissions, if any, resulting from the breakdown and the basis used to quantify the emissions;

(VI) Information substantiating whether the breakdown resulted from operator error, neglect or improper operation or maintenance procedures;

(VII) Information substantiating that steps were immediately taken to correct the condition causing the breakdown, and to minimize the emissions, if any, resulting from the breakdown;

(VIII) A description of the corrective measures undertaken and/or to be undertaken to avoid such a breakdown in the future; and

(IX) Pictures of any equipment which failed, if available.

(iii) Within 15 days of the end of each calendar quarter, the operator shall submit to the Executive Officer a report that lists each occurrence of a breakdown, fault, malfunction, alarm, engine or control system operating parameter out of the acceptable range established by an I&M plan or permit condition, or an emission check that finds excess emissions. Such report shall be in a District-approved format, and for each incident shall identify the time of the incident, the time the operator learned of the incident, specific location, equipment involved, responsible party to contact for further information, to the extent known the causes of the event, the time and description of corrective actions, including shutting an engine down, and the results of all portable analyzer NOx and CO emissions checks done before or after the corrective actions. The operator shall also report if no incidents occurred.

(2) Portable engines:
The operator of any portable engine shall maintain a monthly engine operating log that includes:
(i) Total hours of operation; or
(ii) Type of liquid and/or type of gaseous fuel; and
(iii) Fuel consumption (cubic feet of gas and gallons of liquid).
Facilities subject to Regulation XX may maintain a quarterly log for engines that are designated as a process unit on the facility permit.

(3) Recordkeeping for All Engines
All data, logs, test reports and other information required by this rule shall be maintained for at least five years and made available for inspection by the Executive Officer.

(g) Test Methods
Testing to verify compliance with the applicable requirements shall be conducted in accordance with the test methods specified in Table VIII, or any test methods approved by CARB and EPA, and authorized by the Executive Officer.

TABLE VIII
TESTING METHODS

Pollutant	Method
NO_x	District Method 100.1
CO	District Method 100.1
VOC	District Method 25.1* or District Method 25.3*

* Excluding ethane and methane

A violation of any standard of this rule established by any of the specified test methods, or any test methods approved by the CARB or EPA, and authorized by the Executive Officer, shall constitute a violation of this rule.

(h) Alternate Compliance Option

(1) In lieu of complying with the applicable emission limits by the effective date specified in Table III-B, owners or operators of biogas-fired units that operate under long term fixed price power purchase agreements that have been entered into prior to February 1, 2008 and extend beyond January 1,

2016 may elect to defer compliance by up to two years and no later than January 1, 2018, provided the owner or operator:

(A) Submits an alternate compliance plan and pays a Compliance Flexibility Fee, as provided for in paragraph (h)(2), to the Executive Officer at least 150 days prior to the applicable compliance date in Table III-B, and

(B) Maintains on-site a copy of verification of Compliance Flexibility Fee payment and AQMD approval of the alternate compliance plan that shall be made available upon request to AQMD staff.

(2) Plan Submittal

The alternate compliance plan submitted pursuant to paragraph (h)(1) shall include:

(A) A completed AQMD Form 400A with company name, AQMD Facility ID, identification that application is for a compliance plan (Section 7a of form), and identification that request is for Rule 1110.2 Compliance Flexibility Fee option (Section 9 of form);

(B) Attached documentation of unit permit ID, unit rated brake horsepower (bhp), and fee calculation;

(C) Proof that the power purchase agreement was entered into prior to February 1, 2008 and extends beyond January 1, 2016.

(D) Filing Fee payment; and

(E) Compliance Flexibility Fee payment as calculated by the following equation:

CFF = bhp x R x Y

Where,

CFF = Compliance Flexibility Fee, $

bhp = rated brake horsepower of unit

R = Fee Rate = $47 per brake horsepower per year

Y = Number of years (up to 2 years for engines required to comply by January 1, 2016)

(3) Usage of Compliance Flexibility Fee funds

The funds collected from the Compliance Flexibility Fee will be applied to AQMD NOx reduction programs pursuant to protocols approved under District rules.

(~~h~~i) Exemptions

The provisions of subdivision (d) shall not apply to:

(1) All orchard wind machines powered by an internal combustion engine.

(2) Emergency standby engines, engines used for fire-fighting and flood control, and any other emergency engines approved by the Executive Officer, which have permit conditions that limit operation to 200 hours or less per year as determined by an elapsed operating time meter, and agricultural emergency standby engines that are exempt from a District permit and operate 200 hours or less per year as determined by an elapsed operating time meter.

(3) Laboratory engines used in research and testing purposes.

(4) Engines operated for purposes of performance verification and testing of engines.

(5) Auxiliary engines used to power other engines or gas turbines during start-ups.

(6) Portable engines that are registered under the state registration program pursuant to Title 13, Article 5 of the CCR.

(7) Nonroad engines, with the exception that subparagraph (d)(2)(A) shall apply to portable generators.

(8) Engines operating on San Clemente Island; and engines operated by the County of Riverside for the purpose of public safety communication at Santa Rosa Peak in Riverside County, where the site is located at an elevation of higher than 7,400 feet above sea level and is without access to electric power and natural gas.

(9) Agricultural stationary engines provided that:

(A) The operator submits documentation to the Executive Officer by the applicable date in Table V when permit applications are due that the applicable electric utility has rejected an application for an electrical line extension to the location of the engines, or the Executive Officer determines that the operator does not qualify, due to no fault of the operator, for funding authorized by California Health and Safety Code Section 44229; and

(B) The operator replaces the engines, in accordance with the compliance schedule of Table IX, with engines certified by CARB to meet the Tier 4 emission standards of 40 CFR Part 1039 Section 1039.101, Table 1. These Tier 4 replacement engines shall be considered to comply with Best Available Control Technology; and

(C) The operator does not operate the Tier 4 engines in a manner that exceeds the not-to-exceed standards of 40 CFR Section 1039.101, Paragraph (e), as determined by the test methods of subdivision (g) of this rule.

TABLE IX
COMPLIANCE SCHEDULE FOR INSTALLATION OF NEW TIER 4 STATIONARY AGRICULTURAL ENGINES

Action Required	Due Date
Submit to the Executive Officer applications for permits to construct engine modifications, control equipment, or replacement engines	March 1, 2013
Initiate construction of engine modifications, control equipment, or replacement engines	September 30, 2013, or 30 days after the permit to construct is issued, whichever is later
Complete construction and comply with applicable requirements	January 1, 2014, or 60 days after the permit to construct is issued, whichever is later
Complete initial source testing	March 1, 2014, or 120 days after the permit to construct is issued, whichever is later

(10) An engine start-up, until sufficient operating temperatures are reached for proper operation of the emission control equipment, and an engine shutdown period. The ~~start-up~~ periods shall not exceed 30 minutes, unless the Executive Officer approves a longer period not exceeding 2 hours for an engine and makes it a condition of the engine permit.

(11) An engine start-up, after an engine overhaul or major repair requiring removal of a cylinder head, for a period not to exceed four operating hours.

(12) The initial commissioning of a new engine for a period specified by permit conditions, provided the operator takes measures to reduce emissions and

the duration of the commissioning to the extent possible. The commissioning period shall not exceed 150 operating hours.

ATTACHMENT F

SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT

Revised Draft Staff Report
Proposed Amended Rule 1110.2 – Emissions from Gaseous- and Liquid-Fueled Engines

August 2012

Executive Officer
Barry R. Wallerstein, D.Env.

Deputy Executive Officer
Planning, Rule Development, and Area Sources
Elaine Chang, Dr PH

Assistant Deputy Executive Officer
Planning, Rule Development, and Area Sources
Laki Tisopulos, Ph.D., P.E.

Planning and Rules Manager
Planning, Rule Development, and Area Sources
Joe Cassmassi

Author:	Kevin Orellana – Air Quality Specialist
Reviewed by:	Gary Quinn, P.E. – Program Supervisor William Wong – Principal Deputy District Counsel
Technical Assistance	Alfonso Baez, M.S. – Program Supervisor Wayne Barcikowski – Air Quality Specialist

SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT
GOVERNING BOARD

Chairman:	WILLIAM A. BURKE, Ed.D. Speaker of the Assembly Appointee
Vice Chairman:	DENNIS YATES Mayor, City of Chino Cities Representative, San Bernardino County

MEMBERS:

MICHAEL D. ANTONOVICH
Supervisor, Fifth District
Los Angeles County Representative

JOHN J. BENOIT
Supervisor, Fourth District
Riverside County Representative

MICHAEL CACCIOTI
Council Member, City of South Pasadena
Cities Representative, Los Angeles County/Eastern Region

CLARK E. PARKER, Ph.D.
Senate Rules Committee Appointee

JOSIE GONZALES
Supervisor, Fifth District
San Bernardino County Representative

RONALD O. LOVERIDGE
Mayor, City of Riverside
Cities Representative, Riverside County

JOSEPH K. LYOU, Ph.D.
Governor's Appointee

JUDITH MITCHELL
Council Member, City of Rolling Hills Estates
Cities Representative, Los Angeles County/Western Region

SHAWN NELSON
Supervisor, Fourth District
Orange County Representative

JAN PERRY
Council Member, City of Los Angeles
City of Los Angeles

MIGUEL PULIDO
Mayor, City of Santa Ana
Cities Representative, County of Orange

EXECUTIVE OFFICER:

BARRY R. WALLERSTEIN, D.Env.

TABLE OF CONTENTS

EXECUTIVE SUMMARY

EXECUTIVE SUMMARY

The South Coast Air Quality Management District (AQMD) is the air pollution control agency for all of Orange County and the urban portions of Los Angeles, Riverside and San Bernardino counties. AQMD is responsible for controlling emissions primarily from non-vehicular sources of air pollution.

Rule 1110.2 regulates oxides of nitrogen (NOx), carbon monoxide (CO), and volatile organic compound (VOC) emissions from liquid and gas fueled internal combustion engines operating in the AQMD producing more than 50 rated brake horsepower (bhp). The rule was adopted in 1990 and last amended in 2010 to add an exemption affecting a remote public safety communications site.

The amendment in 2008 set concentration limits for landfill and digester gas-fired engines to become effective on July 1, 2012, subject to a Technology Assessment. The biogas emission standards adopted in 2008, except for CO, were equivalent to the current Best Available Control Technology (BACT) standard. Biogas engines regulated by this rule include approximately 55 engines operated by 13 public and private operators of landfills and wastewater treatment plants. The rule and the adopting resolutions directed staff to conduct and complete a Technology Assessment before July 2010 to confirm the achievability of the July 1, 2012 compliance limits for biogas engines. If the Technology Assessment could not confirm the 2012 limits' achievability, the 2012 limits would not be treated as effective.

District staff presented an Interim Report on the Technology Assessment for Rule 1110.2 Biogas Engines to the Governing Board in July 2010. The report pointed to two potential technologies that were a part of demonstration projects in the basin. However, the permit moratorium in 2009 caused a delay in the startup of these projects. One pilot study has since been successfully completed, but the other demonstration project's startup and completion has been affected by other unforeseen delays. The Interim Technology Assessment mentioned the possible necessity of an adjustment to the July 1, 2012 effective date to facilitate the completion of the technology assessment and implementation of the 2008 amendment.

The proposed amendments will:

- Re-establish the effectiveness of the previously adopted 2012 limits. Allow biogas engine operators ~~three to~~ ~~four~~ three and a half more years to comply with the 2012 emission limits. The new effective date will be January~~July~~ 1, 2016~~5~~ for all biogas engines.~~the first engine or a biogas cleanup system for the entire biogas engine fleet. The remaining engines will have an additional year to comply.~~
- Provide a compliance option with a longer averaging time to engine operators that can demonstrate through continuous emission monitoring systems (CEMS) data mass emission levels at least 10 percent lower than allowable under the rule's proposed concentration limits for NOx and CO. The feasibility of the lower mass

emissions was demonstrated by the recently completed pilot study by Orange County Sanitation District (OCSD), which indicated that lower NOx mass emissions can be achieved in conjunction with longer averaging times. This longer averaging time would be allowed provided that the CEMS data routinely shows emission levels below 11 ppm for NOx and below 250 ppm for CO.

- Provide an alternate compliance option to give operators under long term fixed price power purchase agreements entered into prior to the February 1, 2008 amendments and extending beyond the January 1, 2016 compliance date additional time (up to two years beyond the compliance date) to comply with the emission limits with the payment of a compliance flexibility fee.
- Biogas engines achieving early compliance (i.e. January 1, 2015) will have their permit application fees refunded.

The project will result in 0.9 tons per day of NOx reductions, 0.5 tons per day of VOC reductions, and 20 tons per day of CO reductions. The range of cost effectiveness using the District model is between $1,700 and $3,500 per ton of combined NOx, VOC, and CO reduced (NOx + VOC+ 1/7 CO). Cost effectiveness was calculated based on actual control costs for installations in the Basin and in the Bay Area. Staff also added costs for additional gas cleanup and a 20% capital cost contingency to arrive at an upper cost effectiveness range between $2,600 and $5,900 per ton. It should be noted that recently adopted AQMD NOx regulations ranged in cost effectiveness from $10,000 to $30,000 per ton.

District staff has met on several occasions with stakeholders and the affected community to discuss the feasibility of the required controls and their cost effectiveness. Staff has also met individually with nearly every affected facility operator to discuss site-specific issues. Information on Selective Catalytic Reduction (SCR)/catalytic oxidation-based after treatment technology from the two projects in this Basin and in the Bay Area to date provides ample evidence in support of the feasibility of the proposed limits and the completion of the Technology Assessment. However, on-going demonstration projects with alternate technologies, if successful, could also provide our stakeholders with additional useful information and alternate compliance routes. Staff intends to continue the technology review efforts with stakeholders even after the completion of this rulemaking process.

CHAPTER 1: BACKGROUND

INTRODUCTION

The California Health and Safety Code requires the AQMD to adopt an Air Quality Management Plan (AQMP) to meet state and federal ambient air quality standards and adopt rules and regulations that carry out the objectives of the AQMP. The California Health and Safety Code also requires the AQMD to implement all feasible measures to reduce air pollution. The 2007 AQMP has found that additional reductions are needed to meet the more stringent federal ozone and particulate matter standards. Reductions in NOx will help in main~~at~~taining the federal 24-hour average $PM_{2.5}$ standard in 2014~~9~~, while reductions in NOx and VOC will aid in attaining the ozone standard in 2023. Figure 1 shows the projected baseline emissions for NOx and VOC and the required emissions to achieve the ozone standard in 2023. Further NOx and VOC reductions from Rule 1110.2 biogas engines are essential for achieving compliance with federal and state ambient air quality standards for PM2.5 and ozone.

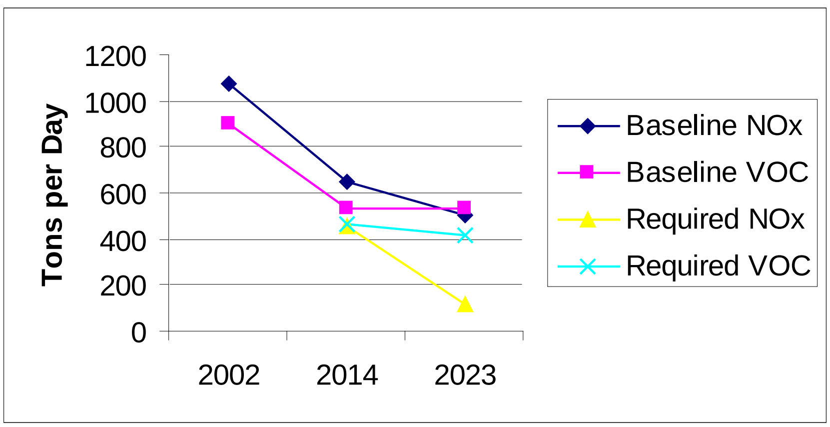


Figure 1. NOx and VOC Baseline Emissions and Emissions Needed to Achieve the 2023 Ozone Standard

Engines that are fueled by biogas (landfill or digester gas) make up about 7% of stationary, non-emergency engines in the AQMD. Of all the combustion sources, these engines inherently have the highest emissions. Rule 1110.2, "Emissions from Gaseous- and Liquid-Fueled Engines," was first adopted in 1990 to address emissions from stationary engines in this category. Since the first adoption of the rule, advances in low NOx burner and post combustion control technology have been demonstrated and implemented on several categories of combustion equipment. In contrast, the current NOx concentration BACT and rule limits for biogas engines are at least twelve times higher than allowed by AQMD boiler rules.

Projected NOx emissions reductions from biogas engines achieving the emissions limits set in the 2008 rule amendment were not included in the State Implementation Plan (SIP) during the 2008 amendment because they were contingent on the completion of a Technology Assessment. However, sufficient information currently exists for the completion of the Final Technology Assessment to support the current amendment of this rule. As a result, the NOx reductions from biogas engines will be incorporated into the SIP to further promote the District's efforts towards the attainment of federal and state $PM_{2.5}$ and ozone air quality standards.

REGULATORY HISTORY

Rule 1110.2 – Emissions from Gaseous- and Liquid-Fired Engines was adopted by the AQMD Governing Board on August 3, 1990. It required that either 1) NOx emissions be reduced over 90% to one of two compliance limits specified by the rule, or; 2) the engines be permanently removed from service or replaced with electric motors. It was amended in September 1990 to clarify rule language and then amended in August and December of 1994 to modify the CO monitoring requirements and to clarify rule language. The amendment of November 1997 eliminated the requirement for continuous monitoring of CO, reduced the source testing requirement from once every year to once every three years, and exempted non-road engines, including portable engines, from most requirements. The amendment in June 2005 made the previously exempt agricultural engines subject to the rule.

To address widespread non-compliance with stationary IC engines, the 2008 amendment augmented the source testing, continuous monitoring, inspection and maintenance (I&M), and reporting requirements of the rule to improve compliance. It also required stationary, non-emergency engines to meet emission standards equivalent to current BACT for NOx and VOC and almost to BACT for CO. This partially implemented the 2007 AQMP control measure for Facility Modernization (MCS-001). Additionally, the 2008 amendment required new electric generating engines to limit emissions to levels nearly equivalent to large central power plants, meeting standards that are at or near the CARB 2007 Distributed Generation Emissions Standards. It also clarified the status for portable engines and set emissions standards for biogas engines to become effective on July 1, 2012 if the July 2010 Technology Assessment would confirm the achievability of those limits.

The 2008 adopting resolution included commitments directing staff to conduct a Technology Assessment to address the availability, feasibility, cost-effectiveness, compliance schedule, and global warming gas impacts of biogas engine control technologies and report back to the Governing Board no later than July 2010. Additionally, the Governing Board directed that the July 2012 biogas emission limits will not be incorporated into the SIP unless the July 2010 Technology Assessment finds that the proposed limits are achievable and cost-effective.

The most recent amendment in July 2010 added an exemption to the rule affecting a remote public safety communications site at Santa Rosa Peak in Riverside County which has limited accessibility in the wintertime.

At the July 2010 Governing Board meeting, staff presented an Interim Technology Assessment to address the board resolution commitments in 2008. The Interim Technology Assessment summarized the biogas engine control technologies to date and the status of on-going demonstration projects. Due to the delays caused by the permit moratorium in 2009, the release of a subsequent report was recommended upon the completion of these projects. The Interim Technology Assessment concluded that feasible, cost-effective technology should be available that can support the feasibility of the July 2012 emission limits, but that the delay in the demonstration projects will likely necessitate an adjustment to the July 1, 2012 compliance date of Rule 1110.2.

SILOXANES IN BIOGAS

Siloxanes are a type of organosilicon compound that exists in many cosmetic, personal and household products. When disposed, these compounds can end up either at wastewater (sewage) treatment plants or in landfills. It is a well known fact that impurities in the biogas affect engine performance. Once oxidized into silicon dioxide (SiO_2) upon combustion, glass-like siloxane deposits can form on moving engine parts such as valves and pistons. Siloxanes in the biogas are responsible for increased engine maintenance, and have the potential to cause significant damage to internal engine components if not removed either before combustion or during routine maintenance service. Additionally, siloxanes, if untreated and combusted, can foul catalyst-based post-combustion controls and make them much less effective in their pollutant removal potential. Siloxanes that make it out through the engine exhaust stream can deposit themselves on the downstream catalyst's available active sites and thereby reduce the pollutant removal efficiency.

In the Interim Technology Assessment, siloxane data was obtained from the Southern California Association of Public Treatment Works (SCAP) and showed that there is variability in the siloxane levels at different locations for digester plants and landfills (Table 1).

Table 1. SCAP Data Showing Siloxane Concentrations in Biogas

Site	Type of Biogas	Average Siloxane Concentration (ppmv)
Palmdale	Digester	0.9
San Bernardino	Digester	0.9
Fountain Valley	Digester	2.59
Huntington Beach	Digester	2.25
Lancaster	Digester	3.9
RP-1	Digester	5.15
JWPCP	Digester	5.31
Hyperion	Digester	8.51
Calabasas	Landfill	0.34
Spadra	Landfill	0.51
Puente Hills	Landfill	3.3

From the data obtained in the Interim Report, the time average siloxane concentration ranges for digester and landfill gas are as follows:

Digester Gas: 0.26 – 9.7 ppmv

Landfill Gas: 0.1 – 3.3 ppmv

During discussions with stakeholders, some have reported levels below 10 ppmv, while others have reported siloxane levels of above 100 ppmv. Regardless of the inlet siloxane level of the biogas, a treatment system capable of handling the baseline level and spikes is absolutely critical to preserve engine and catalyst control system performance.

KEY ISSUES

From ongoing meetings with the affected stakeholders in the Biogas Technology Advisory Committee, staff has summarized key issues that have resulted from those discussions.

1. *Cost of Biogas Cleanup*. The capital and operating costs for cleaning up the biogas are very high, especially for those applications that have variable and elevated siloxane levels.
2. *Space Requirements*. Some facility owners and operators may have to build ancillary structures, such as elevated platforms, to accommodate the control equipment which increases the installation costs. This is due to specific site constraints with existing equipment and structures.

3. *Cost of Exhaust Gas Cleanup*. Post-combustion control technologies such as Catalytic Oxidation and Selective Catalytic Reduction (SCR) are expensive to install and operate.
4. *Contracted Facilities*. Some facility operators only lease the gas supplied by a landfill and combust the gas for power production. These entities allege that they are bound by power purchase agreements that may prevent them from installing control equipment to reduce emissions within the next few years.
5. *Life of Landfill Operations/Equipment*. The volume and quality of landfill gas decreases once the landfill ceases to accept municipal solid waste. Some facilities have expressed concerns that by the time the proposed limits become effective, the gas quality will not be sufficient to utilize an engine. These operators feel that they should not retrofit equipment that will be placed out of service within a short time frame.
6. *Selling Gas to Pipeline*. Although it is not currently allowed in the state of California, producing pipeline-quality gas from landfill gas can be a possibility in the future through changes in state regulations (If this is the case, then there will be no utilization of engines and will consist of extensive gas cleanup only).
7. *Flaring as an Option*. Stakeholders have said that if the control technologies are too expensive, they will be left with no viable alternative but to shut down the engines and flare the biogas.

Responses to these comments are presented in Attachment B.

AFFECTED INDUSTRIES

Rule 1110.2 applies to stationary and portable reciprocating internal combustion engines (ICEs) over 50 brake horsepower (bhp). PAR 1110.2 affects the subset that contains engines fueled with biogas, which are those that are operated by landfills and wastewater treatment plants. Biogas engines are lean-burn engines that operate similarly to lean-burn natural gas-fired engines with a higher level of exhaust oxygen.

Landfills produce gas that results from the breakdown of municipal solid waste. This gas is primarily composed of methane and carbon dioxide. The gas is collected in a series of wells that transports it via pipeline to the landfill gas fired engines. The collected landfill gas fires one or more biogas engines with or without supplementation of natural gas.

Wastewater treatment plants produce digester gas from the plant's digesters. A digester uses heat and bacteria in an oxygen-free (anaerobic) environment to break down sewage sludge. A by-product of this process is biogas that contains methane. This biogas also fires one or more biogas engines with or without supplementation of natural gas. An advantage with using ICEs at wastewater treatment plants is that these are combined heat and power (CHP) units. The waste heat created by the engine can be recovered and used to heat the plant's digesters, resulting in energy savings.

Whether coming from a landfill or an anaerobic digester, the biogas is used to fire an internal combustion engine with a generator to produce electricity. Some facilities are self-generating facilities that use the electricity to power their processes internally. Others sell off this generated power to the local utility grid. The wastewater treatment plants are primarily operated by public entities and utilities, while the landfills are operated by either public or private operators. There are a total of 8 public operators and 5 five private operators for biogas engines in the South Coast Basin.

There are 55 biogas engines operating in the Basin. Of these engines, 27 are digester gas-fueled and 28 are landfill gas-fueled. These engines are operated by 13 independent operators at 22 locations (6 operate digester gas-fueled engines and 7 operate landfill gas-fueled engines).

Despite past efforts to reduce emissions, biogas-fueled engines remain the dirtiest in terms of mass per unit power produced in the Basin, even though they are fired with renewable fuel. Even at BACT, these engines pollute significantly more than large central generating stations on a pound per megawatt-hour basis (Figure 2). For biogas ICEs, the NOx emissions are over 25 times higher than those of central power plants, 119 times higher for VOC, and 75 times higher for CO.

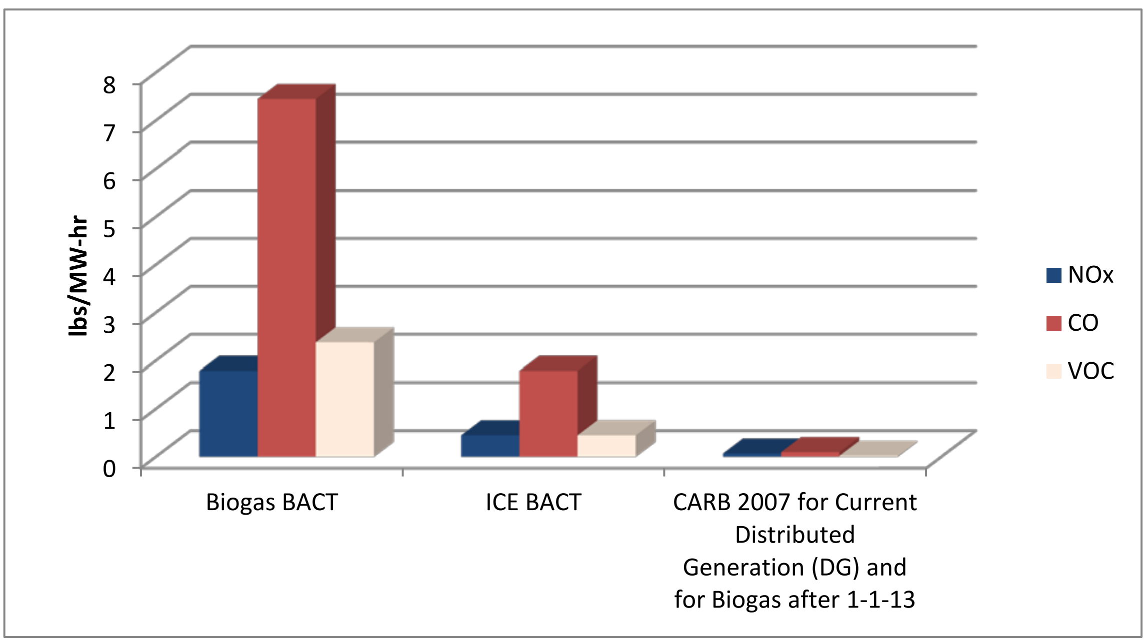


Figure 2. Current BACT for Biogas ICEs and Natural Gas ICEs vs. Central Generating Station BACT

During the 2010 Interim Technology Assessment, approximately 66 engines fueled by biogas were identified. Since that time, however, the number has decreased to 55 due to some engines being placed out of service. Nonetheless, the remaining biogas engines are among the top NOx emitters amongst stationary, non-emergency engines. Table 2 lists the top 25 NOx emitters based on annual reporting data for 2010. In this table, 13 of the 25 top NOx emitters in the basin are biogas-powered stationary, non-emergency engines. Forty-three percent of the NOx emissions in this table come from the 13 biogas engines. The remaining non-biogas facilities are now subject to the current Rule 1110.2 limits.

Table 2. "Top 25" Facilities with Highest NOx Emissions from Stationary, Non-Emergency Engines (Pounds per Year) in 2010

Facility	ID No.	NOx	ROG	CO	Fuel(s)
U.S. GOVT, DEPT OF NAVY	800263	110,713	8,967	24,390	Diesel
U.S. GOVT, DEPT OF NAVY	800263	80,714	9,701	26,387	Diesel
EXXONMOBIL OIL CORPORATION	800089	69,961	5,594	15,215	Diesel
LA COUNTY SANITATION DISTRICT-PUENTE HILLS	***25070***	***52,796***	***18,068***	***284,104***	***Landfill Gas***
ORANGE COUNTY SANITATION DISTRICT	***29110***	***48,912***	***68,945***	***611,663***	***Digester Gas***
ORANGE COUNTY SANITATION DISTRICT	***17301***	***41,478***	***43,767***	***426,682***	***Digester Gas***
U.S. GOVT, DEPT OF NAVY	800263	38,469	3,827	10,408	Diesel
CRIMSON RESOURCE MANAGEMENT	142517	38,093	507	64,119	Natural Gas (Rich-Burn)
MM LOPEZ ENERGY LLC	***104806***	***35,662***	***10,707***	***142,482***	***Landfill Gas***
MM PRIMA DESHECHA ENERGY, LLC	***117297***	***32,599***	***6,321***	***127,325***	***Landfill Gas***
MM PRIMA DESHECHA ENERGY, LLC	***117297***	***31,474***	***14,005***	***141,724***	***Landfill Gas***
EXXONMOBIL OIL CORPORATION	800089	28,192	2,254	6,131	Diesel
MM LOPEZ ENERGY LLC	***104806***	***28,189***	***11,753***	***110,606***	***Landfill Gas***
U.S. GOVT, DEPT OF NAVY	800263	21,923	2,181	5,931	Diesel
EOP - 10960 WILSHIRE LLC	119133	20,083	267	33,805	Natural Gas (Rich-Burn)
HOLLYWOOD PARK LAND COMPANY LLC	145829	19,792	1,583	4,304	Diesel
SAMUEL P LEWIS DBA CHINO WELDING & ASSEM	150351	19,542	260	32,894	Natural Gas (Rich-Burn)
TOYON LANDFILL GAS CONVERSION LLC	***142417***	***18,000***	***9,991***	***100,575***	***Landfill Gas***
ORANGE, COUNTY OF - SHERIFF DEPT, FAC OP	72525	17,314	499	1,344	Natural Gas (Lean-Burn)
BREA PARENT 2007, LLC	***113518***	***17,033***	***1,099***	***4,555***	***Landfill Gas***
HUNTINGTON BEACH CITY, WATER DEPT	20231	15,370	205	25,871	Natural Gas (Rich-Burn)
BREA PARENT 2007, LLC	***113518***	***15,346***	***784***	***3,140***	***Landfill Gas***
BREA PARENT 2007, LLC	***113518***	***14,181***	***1,052***	***4,958***	***Landfill Gas***
WASTE MGMT DISP & RECY SERVS INC (BRADLEY)	***50310***	***13,934***	***3,465***	***60,087***	***Landfill Gas***
WASTE MGMT DISP & RECY SERVS INC (BRADLEY)	***50310***	***13,839***	***3,823***	***67,514***	***Landfill Gas***
TOTALS, PPY		843,607	229,624	2,336,216	
TOTALS, TPY		421.8	114.8	1,168.1	
TOTALS, TPD		1.16	0.31	3.20	

PUBLIC PROCESS

Since the 2008 amendment, staff has held eight Biogas Technology Advisory Committee Meetings with representatives from affected facilities, manufacturers, consultants and other interested parties. The Biogas Technology Advisory Committee was part of the ongoing commitment to finalize the Technology Assessment for biogas engines. In October 2010 staff met with the regulated community to discuss cost issues related to the emission standard adopted as part of the 2008 amendment. Since the July 2010 Interim Report, the Biogas Technology Advisory Committee met in September 2011, January 2012, April 2012, ~~and~~ May 2012, and August 2012. Two Public Workshops were held in February 2012 and April 2012. Staff also has had several meetings with control equipment vendors and also manufacturers of emerging technologies that may provide an alternative to electrical power generation by traditional internal combustion methods. In addition, staff has met individually with nearly every biogas facility operator to discuss site-specific issues, technologies, long-term plans for existing biogas engines, and costs. Several site visits were also conducted by staff at affected facilities.

CHAPTER 2: CONTROL TECHNOLOGIES

INTRODUCTION

Controlling emissions for lean-burn biogas engines has many challenges. Fortunately, the same add-on control technologies used in the control of lean-burn natural gas engines can be employed in biogas engines with proper fuel pretreatment. Additionally, other technologies have emerged that have been shown to result in emissions well below the proposed rule limits.

The Final Technology Assessment attached to this staff report summarizes staff's findings to date regarding the feasibility of the biogas engine emission limits. Data collected from a completed demonstration project in the Basin and from a landfill in the Bay Area provides substantial evidence in support of the proposed emission limits for biogas engines. In addition to feasibility, the Final Technology Assessment also includes cost-effectiveness, compliance schedule, global warming impacts, and the impacts of potential flaring. The Final Technology Assessment provides a complete description of the control technologies for this amendment, and is presented as an attachment to this document (Attachment A). What follows is a summary of the technologies discussed in the Technology Assessment.

BIOGAS CLEANUP

As mentioned in the previous section, the cleanup of the inlet fuel for biogas engines can serve two purposes: longer operating time with less engine maintenance and protection of post-combustion catalysts from impurities. Methylated siloxanes in the biogas are a chief contributor to catalyst fouling and increased engine maintenance. The 2008 Interim Technology Assessment concluded that an engine with a gas cleanup system capable of effectively removing siloxanes can protect post-combustion catalysts and make multi-pollutant reductions feasible. Although the levels of siloxanes can vary by facility, a properly designed system can perform effectively to remove siloxanes as well as many other impurities such as moisture, particulates, VOCs and sulfur compounds. Two installations in California have shown that gas cleanup can protect catalysts and lower engine maintenance costs. The installations at Ox Mountain Landfill in the Bay Area and at the Orange County Sanitation District (OCSD) utilize gas cleanup systems and post-combustion catalytic control systems that have resulted in favorable reductions in NOx, VOC, and CO, while performance data demonstrates effective siloxane removal and protection of post-combustion catalysts. There are two main types of systems for siloxane removal, regenerative and non-regenerative. Ox Mountain uses a regenerative system, while OCSD relies on a non-regenerative system. However, the gas cleanup systems at both Ox Mountain and OCSD use activated carbon as the adsorption media for the gas impurities. The difference is that Ox Mountain heats the carbon and purge gas in a regenerative cycle to "reactivate" the carbon whereas OCSD simply replaces the spent media with fresh activated carbon.

CATALYTIC OXIDATION/SELECTIVE CATALYTIC REDUCTION

A technology that has been around for many years for natural gas ICE after-treatment is catalytic oxidation and selective catalytic reduction (SCR). Catalytic oxidation removes VOC and CO from the exhaust stream while SCR removes NOx with the use of urea injection. This technology is most effective in lean-burn engines. Before effective gas cleanup became available, catalyst poisoning was a problematic issue with this application for biogas engines. The pilot study at OCSD and the installation at Ox Mountain both used these two technologies in conjunction with biogas cleanup for removal of NOx, VOC, and CO. The results from OCSD's pilot demonstration and Ox Mountain show that the proposed rule's emission limits are achievable on a consistent basis. Source test and CEMS data from both installations show that properly cleaned biogas does not foul or poison the oxidative and SCR catalysts, ensuring reliable multi-pollutant removal.

NOXTECH

NOxTech is a selective non-catalytic reduction control technology that treats the exhaust stream of IC engines, reduces NOx, VOC, and CO, and does not require gas cleanup. In the NOxTech system the exhaust gases are heated to a temperature that incinerates VOC and CO without generating thermal NOx, and then removes exhaust NOx using urea injection. Eastern Municipal Water District (EMWD) installed a NOxTech unit at a facility that operates three natural gas engines. The facility is currently operating the NOxTech system, but experienced some setbacks due to the high heat and rapid combustion created from the natural gas engine exhaust. An enhanced system with exhaust gas recirculation (EGR) has been installed and preliminary data has shown that the NOx limits are achievable. Further optimization is currently underway to establish consistent results. This system has the possibility of being less costly than the oxidation catalyst/SCR system because of potentially lower operations and maintenance costs, plus the added benefit of not requiring the high capital outlay of an inlet biogas cleanup system. It should be noted that the benefits of biogas treatment to engine wear and maintenance are forgone if a facility solely relies on NOxTech.

ALTERNATIVE TECHNOLOGIES

Other technologies exist that can be used in place of ICEs and are capable of producing much lower emission profiles. Fuel cells are capable of producing power electrochemically while producing near zero emissions. Fuel cells are sensitive to impurities; therefore, a gas cleanup system is essential. There are many fuel cell installations all over California running on anaerobic digester gas, including five in the South Coast Basin at wastewater treatment facilities.

Flex Energy combines regenerative thermal oxidation with microturbine technology for power production with near zero emissions. This system is especially applicable to facilities that produce low methane biogas, such as closed landfills. One system is operating at a military base in Georgia and a second is targeted to become operational in Orange County this year. This system does not require gas cleanup and can continue to provide power many years after a landfill closes and its methane production drops off.

Hydrogen Assisted Lean Operation, or HALO, is an emerging technology that involves the injection of hydrogen gas into the biogas fuel stream before combustion. This enrichment of hydrogen improves the lean limit combustion stability of the fuel, resulting in lower pollutant emissions. This technology is set to be tested and demonstrated at a wastewater treatment facility in the Basin.

Other combustion technologies such as gas turbines, microturbines, and boilers are also capable of producing power and have lower emission profiles than IC engines. Several facilities in the Basin already use these technologies as the sole source of power production or as a supplemental source to IC engines. Turbines and microturbines require gas cleanup, while boilers are less sensitive to impurities in the biogas.

SELF-GENERATING INCENTIVES

The California Public Utilities Commission (CPUC) offers incentives for facilities that produce at least 75% of their power from renewable fuels, such as biogas, and use that electricity to power internal operations. The Self-Generation Incentive Program (SGIP) provides incentives that can aid in offsetting some of the capital costs from biogas projects. As of November 2011, a $2.00 per Watt biogas incentive has been offered that can be added to other incentives based on the type of technology used, such as fuel cells, gas turbines, microturbines and IC engines. For example, the combined heat and power (CHP) fuel cell incentive is $2.25 per Watt, so if combined with the biogas incentive, the total incentive is $4.25 per Watt. So for a 1 MW CHP fuel cell installation running on biogas, the incentive would amount to 4.25 million dollars. The incentives are also contingent on the facilities meeting specific capacity factors and not exporting more than 25% of the power produced to the grid.

CHAPTER 3: SUMMARY OF PROPOSED RULE 1110.2

PROPOSED AMENDED RULE REQUIREMENTS

PROPOSED AMENDED RULE REQUIREMENTS

The key proposed amendments can be summarized as follows:

- Re-establish the effectiveness of the previously adopted 2012 limits. Allow biogas engine operators three and a half~~three~~ more years to comply with the 2012 emission limits. The new effective date will be January~~July~~ 1, 2016~~5~~ for all biogas engines.~~the first engine or a biogas cleanup system for the entire biogas engine fleet. The remaining engines will have an additional year to comply.~~
- Provide a compliance option with a longer averaging time to engine operators that can demonstrate through continuous emission monitoring (CEMS) data mass emission levels at least 10 percent lower than allowable under the rule's proposed concentration limits.
- Provide an alternate compliance option to give operators under long term fixed price power purchase agreements entered into prior to the February 1, 2008 amendments and extending beyond the January 1, 2016 compliance date additional time for engine retrofits beyond the proposed compliance date (up to two years) with the payment of a compliance flexibility fee.

The feasibility of the lower mass emissions was demonstrated by the recently completed pilot study by OCSD, which indicated that lower mass emissions can be achieved in conjunction with longer averaging times. This longer averaging time would be allowed provided that the CEMS data routinely shows NOx emission levels below 11 ppm (the proposed standard).

To reflect the additional time needed to complete the Final Technology Assessment, District staff is proposing to allow biogas engine operators more time for compliance with the emission limits adopted in the 2008 amendment. Subparagraph 1110.2(d)(1)(C) establishes the emission standards for biogas engines, specifies the effective dates for the emission limits, and provides the compliance schedule for all biogas engines, as listed in Table 3 on the next page. The table is split into two parts: The first part reflects the currently effective limits and the second part establishes the ~~3 to 4~~ three and a half year delay of the 2012 effective date limits for compliance. ~~For operators planning to add engine controls that do not require gas cleanup (i.e. NOxTech, H_2 injection), the first engine will have to comply by July 1, 2015, while the remaining engines will have one additional year to comply. For operators planning to add engine controls that do require biogas cleanup (oxidation catalyst/SCR), the biogas cleanup system servicing the entire biogas engine fleet will have to be installed by July 1, 2015, while the catalytic aftertreatment controls for all the engines will have to be installed by July 1, 2016.~~

Table 3. Proposed Concentration Limits for Biogas Engines

<table>
<tr><th colspan="3">CONCENTRATION LIMITS FOR LANDFILL AND DIGESTER GAS (BIOGAS)-FIRED ENGINES</th></tr>
<tr><td>NO_x (ppmvd)[1]</td><td>VOC (ppmvd)[2]</td><td>CO (ppmvd)[1]</td></tr>
<tr><td>bhp ≥ 500: 36 x ECF[3]
bhp < 500: 45 x ECF[3]</td><td>Landfill Gas: 40
Digester Gas: 250 x ECF[3]</td><td>2000</td></tr>
<tr><th colspan="3">CONCENTRATION LIMITS EFFECTIVE JANUARY 1, 2016</th></tr>
<tr><td>NOx (ppmvd)[1]</td><td>VOC (ppmvd)[2]</td><td>CO (ppmvd)[1]</td></tr>
<tr><td>11</td><td>30</td><td>250</td></tr>
<tr><th colspan="3">~~CONCENTRATION LIMITS AND COMPLIANCE SCHEDULE FOR LANDFILL AND DIGESTER GAS (BIOGAS)-FIRED ENGINES~~</th></tr>
<tr><td>~~Category~~</td><td>~~Limit~~</td><td>~~Unit(s) Shall be in Full Compliance on or before~~</td></tr>
<tr><td>~~First Engine or Biogas Cleanup System for entire Biogas engine fleet~~</td><td rowspan="2">~~NO_x (ppmvd)[1]: 11~~
~~VOC (ppmvd)[2]: 30~~
~~CO (ppmvd)[1]: 250~~</td><td>~~July 1, 2015~~</td></tr>
<tr><td>~~Remaining Engine(s)~~</td><td>~~July 1, 2016~~</td></tr>
</table>

1 Parts per million by volume, corrected to 15% oxygen on a dry basis and averaged over 15 minutes.

2 Parts per million by volume, measured as carbon, corrected to 15% oxygen on a dry basis and averaged over the sampling time required by the test method.

3 ECF is the efficiency correction factor.

The subparagraph in Rule 1110.2(d)(1)(C) that reads:

> "The concentration limits effective on or after July 1, 2012 shall become effective provided the Executive Officer conducts a technology assessment

> that confirms that the limits are achievable, and reports to the Governing Board by July 2010, at a regularly scheduled public meeting,"

will be removed due to the two year delay of the emission limit effective date for biogas engines, and the subparagraph's expired applicability.

Staff is proposing the following restructuring of paragraph (d)(1) to improve its readability. Subparagraph (d)(1)(D) is added to contain a provision that does not allow a biogas engine to operate in a manner that exceeds the emission limits in (d)(1)(C).

Subparagraph (d)(1)(E) provides an incentive for operators that achieve early compliance. Specifically, if a biogas engine achieves compliance by no later than January 1, 2015, that engine's permit application fees will be refunded to the owner or operator. It must be established to the satisfaction of the Executive Officer that a biogas engine is complying with the emission limits in Table III-B.

Subparagraph (d)(1)(F~~E~~) will specify the provision for the percentage of natural gas burned. This provision was relocated from subparagraph (d)(1)(C) of the current rule. Once a biogas engine complies with the proposed emission standards, the 10% natural gas limit will no longer apply.

Subparagraph (d)(1)(G~~F~~) will contain the exception for low-usage engines since it is not cost-effective to add controls to these units. This provision was also relocated from subparagraph (d)(1)(C) of the current rule.

Subparagraph (d)(1)(H~~G~~) will contain a provision for operators requiring a longer averaging time.

> "An operator of a biogas engine may determine compliance with the NOx and/or CO limits of Table III-B by utilizing a longer averaging time as set forth below, provided the operator demonstrates through CEMS data that the engine is achieving a concentration at or below 9.9 ppmv for NOx and 225 ppmv for CO (if CO is elected for averaging), ~~(~~each corrected to 15% O_2~~)~~, over a 4 month time period. An operator may utilize a monthly fixed interval averaging time for the first 4 months of engine operation and up to a ~~12~~ 24 hour fixed interval averaging time thereafter."

As evidenced by the demonstration project by Orange County Sanitation District (OCSD), there were occasional spikes in the NOx CEMS readings that were above the 11 ppm limit. This occurred approximately 0.9% of the time. To ensure compliance with the proposed limits, staff is proposing to allow biogas engine operators a longer averaging time beyond 15 minutes. However, this is contingent on the performance of the control equipment determined by a CEMS. The longer averaging time will be allowed if the NOx and/or CO emissions are at least 10% below what is allowable (at or below a concentration of 9.9 ppmv for NOx and 225 ppmv for CO). For the first four months of operation, a monthly averaging time will be allowed for the purposes of equipment optimization. After four months, a twenty four~~twelve~~ hour averaging time can be implemented to demonstrate compliance. The longer averaging periods are fixed interval (or block) averages, not rolling averages. The longer averaging time may be used only if an engine is achieving the NOx and/or CO emission levels (9.9 ppmv and 225 ppmv, respectively) averaged over a 4 month period.

Since Rule 1110.2 does not require a CO CEMS on lean-burn engines, the requirements of subparagraph (d)(1)(H) apply to CO only if a biogas engine operator elects to install a CO CEMS for improved, real-time monitoring (e.g. oxidation catalyst performance). ~~The longer averaging option is not intended to apply to time-shared CEMS, since this type of system does not collect data continuously over the required time periods in the proposed rule.~~

To prevent artificial averaging of zero data when, for instance, the engine is not operating, or when the CEMS is undergoing periods of calibration or audit, clause 1110.2(d)(1)(H~~G~~)(i) will read:

> "For ~~the~~ purposes of determining compliance using a longer averaging time: An operator shall not average data during one-minute periods in which the underlying equipment is not operated or when the CEMS is undergoing ~~periods of calibration or audit~~zero or calibration checks, cylinder gas audits, or routine maintenance in accordance to the provisions in Rules 218 and 218.1."

The operation of the CEMS shall comply with the existing requirements of Rules 218 and 218.1. Rule 218.1 requires that the data points for CEMS analyzers are to be within 10 and 95 percent of the full span or full scale range. In addition, if any data point falls above 95 percent of the full scale range, that value shall be invalid for quantification. For a biogas engine using a longer averaging time, if a CEMS reading falls above 95 percent of the full scale range while the engine is operating, the invalid data point would not be factored into the longer averaging period. Furthermore, the magnitude of the excursion would be unknown since it is outside the range of the analyzer. To address these excursions, a missing data procedure will be applied to quantify the excursions for inclusion into the calculation of the longer averaging time.~~Whenever valid CEMS emission data cannot be obtained or recorded, aside from documented malfunctions and breakdowns, a missing data procedure will be applied.~~ For biogas engines, the NOx missing data shall use a concentration of 3~~6~~3 ppmv (corrected to 15% O_2) for every missing time period above 95 percent of the full scale range and the CO missing data shall use a concentration of 750~~2000~~ ppmv (corrected to 15% O_2), if the engine is operating during these excursions. This is equivalent to three times the NOx and/or CO emissions limits in Table III-B.~~If the CEMS cannot obtain data per the requirements of AQMD Rules 218 and 218.1, then the substitute data must be used.~~ Clause 1110.2(d)(1)(H~~G~~)(ii) will read:

> "~~For purposes of determining compliance using a longer averaging time: An operator shall use substitute CEMS data for all other one-minute CEMS data when NOx and/or CO emissions data has not been obtained or~~

> ~~recorded or does not meet the requirements of Rules 218 and 218.1. A concentration of 36 ppmv for NOx and 2000 ppmv for CO (each corrected to 15% O_2) shall be used as substitute data.~~Notwithstanding the requirements of Rules 218 and 218.1, for one-minute time periods where NOx and/or CO CEMS data are greater than 95 percent of the Rule 218.1 Full Scale Range while the underlying equipment is operating, an operator shall use substitute data. A concentration equivalent to 3 times the NOx and/or CO emission limits in Table III-B (each corrected to 15% O_2) shall be used as substitute data."

The~~is~~ following provision discourages the intentional shutdown of a CEMS for reasons other than valid malfunctions and~~,~~ breakdowns~~, or inability to meet the requirements of Rules 218 and 218.1~~. Clause (d)(1)(H)(iii) clearly states that:

> "The intentional shutdown of a CEMS to circumvent the emission limits of Table III-B while the underlying equipment is in operation shall constitute a violation of this rule."

The longer averaging option is not intended to apply to time-shared CEMS, since this type of system does not collect data continuously over the required time periods in the proposed rule. This is stated in clause (d)(1)(H)(iv).

The revised staff proposal provides some biogas engine operators who have entered into fixed price, long term power purchase agreements with local utilities, prior to the February 1, 2008 amendments that first established the July 2012 biogas engine emission limits, with the option to defer compliance by up to two years from the January 1, 2016 compliance date, up to January 1, 2018 with the payment of a compliance flexibility fee. Subdivision (h) outlines the requirements for the plan submittal and the calculation of the compliance flexibility fee. The fee is based on the Carl Moyer cost effectiveness of \$17,200 per ton and is calculated based on the NOx reductions of PAR 1110.2. The total cost per year is divided by the sum brake horsepower (bhp) of all the affected biogas engines to arrive at \$47 per bhp per year. The compliance flexibility fee is calculated by taking the fee rate (\$47/bhp-yr) and multiplying by the rated brake horsepower of the unit and then multiplying by the number of years to defer (1 or 2 years). The fees collected from this alternate compliance option will applied to AQMD NOx reduction programs. This alternate compliance option is not available for operators who have entered into long term power purchase agreements following the February 1, 2008 amendments.

The proposed amendments will provide biogas engine facilities with additional time to implement the proper controls to meet the emission limits. Biogas operators will also have additional time to explore the use of alternative technologies that do not require the combustion of biogas by internal combustion engines.

Several minor administrative changes were also included to provide clarity with respect to references within the rule. In addition, the following four clarifications, although minor in nature, necessitate either a change in the rule language or an explanation detailed below.

The first clarification involves adjustments to oxygen sensor set points and the frequency of portable analyzer checks in Rule 1110.2 subclause (f)(1)(D)(iii)(I). In the current rule if an engine is in compliance for three consecutive emission checks without any O_2 set point adjustments, the engine can move up to a monthly testing schedule or test every 750 hours, whichever occurs later. If an engine then encounters a non-compliant emissions test result or if the O_2 sensor is replaced for a rich-burn engine with a three way catalyst, it must revert to the more frequent testing schedule. The objective of periodic monitoring is to prevent non-compliance and the objective of not allowing any O_2 set point adjustments during the emission tests is to prevent circumvention of the rule. However, if an operator is proactively adjusting the O_2 set points as a means of preventing a non-compliant situation, the current construct of the rule would suggest that the operator is still required to return to the more frequent testing schedule. Clearly, the intent of the rule was never to discourage such proactive maintenance approaches. To address this, the portable analyzer testing frequency can remain unchanged if the engine is in compliance before and after the O_2 set point adjustment at the air-to-fuel ratio controller (AFRC). This will maintain compliant operation of the engine without allowing the emissions to reach a non-compliant level, while preventing a reversion to a more frequent testing schedule. The operator must perform an emissions check after the set point adjustment to ensure that the engine is operating in compliance after the set point change. This post-adjustment testing is to be performed notwithstanding the requirements of subclause (f)(1)(D)(iii)(IV), which prohibits any control system tuning within 72 hours prior to an emission check. Subclause 1110.2(f)(1)(D)(iii)(I) will now read:

> "If an engine is in compliance for three consecutive emission checks, without any adjustments to the oxygen sensor set points, then the engine may be checked monthly or every 750 engine operating hours, whichever occurs later, until there is a noncompliant emission check or, for rich-burn engines with three-way catalysts, the oxygen sensor is replaced. <u>When making adjustments to the oxygen sensor set points, returning to a more frequent emission check schedule is not required if the engine is in compliance with the applicable emission limits prior to and after the set point adjustments, notwithstanding the requirements of (f)(1)(D)(iii)(IV).</u>"

The second clarification involves the shutdown period for an engine. The current rule provides up to 30 minutes after an engine start-up for non-compliant emissions. Emission control equipment takes about 30 minutes from a cold start-up to attain a proper operating temperature to effectively remove pollutants and achieve compliant results. Engine operators have also experienced a similar situation during a gradual shutdown where there are non-compliant events, specifically documented on those engines equipped with CEMS. Engine operators often need to shut an engine down over a short period of time (typically no more than 30 minutes) to allow it to cool and prevent unnecessary damage from a hard stop. Under the current rule, many operators have to shut down an engine quickly to prevent non-compliant results and potential enforcement action. To address this issue, the exemption in Rule 1110.2(h)(10) will also include a 30 minute shutdown period in addition to the 30 minute start-up period. The emissions provisions in subdivision (d) shall not apply to:

> "An engine start-up, until sufficient operating temperatures are reached for proper operation of the emission control equipment, and an engine shutdown period. The periods shall not exceed 30 minutes, unless the Executive Officer approves a longer period not exceeding 2 hours for an engine and makes it a condition of the engine permit."

The third clarification also involves an exemption in subdivision (h). Rule 1110.2(h)(11) allows an exemption of emission requirements for four operating hours when starting up an engine after an overhaul or major repair that involves the removal of the cylinder head. During these types of repairs, particles or liquids can be left behind from the engine work and take some time to burn off or expel. If an engine catalyst is in operation during this start-up period, significant damage can result from the operation of the engine. Physical damage to the catalyst can result from the particulates and a decrease in catalyst performance can result from contaminant poisoning. This impact can be immediate or can result in a sooner than expected catalyst replacement, which can become a significant cost to the operator. To prevent this from occurring, it has been noted that the four-hour exemption following an engine overhaul or major repair requiring removal of a cylinder head would also allow the temporary removal of the catalyst to prevent its damage.

The final clarification involves the testing and monitoring provisions in Rule 1110.2(f)(1)(D). Under the current rule, portable analyzer emission checks are performed in accordance to the testing frequency outlined in clause (f)(1)(D)(iii). In the event that a scheduled portable analyzer emission check occurs during the same monitoring period as a regularly scheduled source test per (f)(1)(C), the source test results can be used in lieu of the portable analyzer check. The reference source test methods in subdivision (g) of the rule are more stringent than the portable analyzer test method, so this clarification is being made in this report to prevent redundancy in testing within the same time period.

CHAPTER 4: IMPACT ASSESSMENT

EMISSIONS IMPACTS AND COST EFFECTIVENESS

The proposed amendments will have emissions impacts on biogas engines regulated by Rule 1110.2. Since biogas engines emit significantly more pollutants than natural gas engines and central power plants, the proposed emission standard will reduce NOx, VOC, and CO emissions drastically. On an aggregate pollutant basis, current biogas engine emissions are over 55 times higher than those of central power plants. The proposed amendments will result in up to 74% emission reductions (Figure 3).

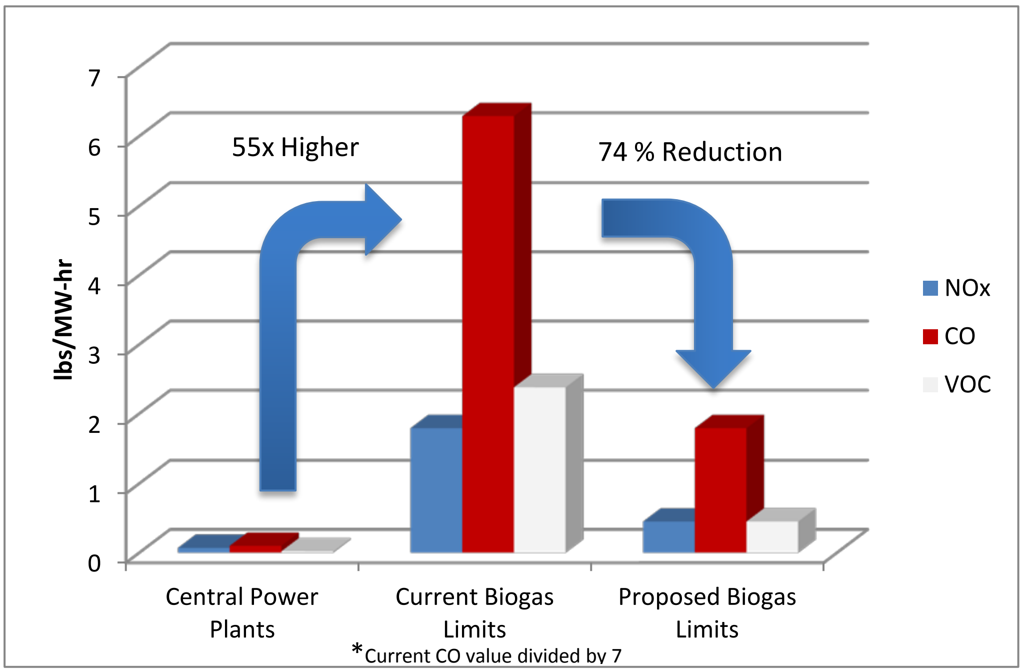


Figure 3. Emissions from Biogas ICEs versus Central Power Plants

The current emissions from biogas engines amount to approximately 1.3 tons per day of NOx, 0.8 tons per day of VOC, and 25.6 tons per day of CO. The current emissions are calculated from the current Rule 1110.2 rule limits and permit limits, while the future emissions are calculated from the proposed Rule 1110.2 limits. Permit limits were used for some engines because they were permitted at BACT or have more stringent permit limits than in the current rule. The emission reductions are 0.9 tons per day of NOx, 0.5 tons per day of VOC, and 20.0 tons of CO. The reductions will occur in two steps. The first reductions will occur by January~~July~~ 1, 2016~~5~~ and second step of reductions will occur one to two years later when all biogas engines will comply with the rule limits under the alternate compliance option.

Emissions are calculated for NOx, VOC, and CO. The emission reductions for CO are discounted by one seventh because its ozone-formation potential is approximately one seventh from that of NOx. For calculating cost effectiveness, the District uses the Discounted Cash Flow (DCF) model, which takes into consideration both capital cost plus annual operating and maintenance costs. This use of this model is consistent with previous rulemaking proposals and past control measures because it links the cost of the project with its environmental benefits. The equipment is given a twenty year life and a 4% interest rate is applied. The calculated present worth value (PWV) is then divided by the summation of the emission reductions and the length of the project (20 years).

The cost figures submitted by OCSD from their final report were used as a benchmark for evaluating costs for several biogas engine operations. The OCSD data which includes operations for the highest brake horsepower portion of the engine distribution (3,471 bhp) were scaled across different digester and landfill gas engine sizes to estimate installation and operating costs for different engine sizes, ranging from 250 bhp to 4,200 bhp. The non-catalyst installed cost was calculated by using the general chemical engineering cost estimating practice for industrial equipment packages of $bhp^{0.6}$. The other costs were scaled based on brake horsepower alone.

The cost effectiveness was estimated to range from $1,700 to $3,500 per ton of NOx, VOC, and CO/7 reduced. 8,000 annual operating hours was assumed for the engines. The cost effectiveness was also calculated for a landfill installation with a more expensive regenerative gas cleanup system. These costs were obtained from the Bay Area AQMD for the installation at Ox Mountain Landfill. The cost effectiveness calculated using Ox Mountain’s capital and operating costs for the proposed amended rule’s emission reductions is $2,300 per ton of NOx, VOC, and CO/7. Staff also calculated cost effectiveness to account for additional gas cleanup and associated contingencies, based on stakeholder feedback. Using vendor quotes for gas cleanup systems, two additional cost effectiveness curves were created reflecting the additional gas cleanup and an added 20% capital cost contingency. The upper cost effectiveness curve has a range from $2,600 to $5,900 per ton. The upper and lower (base level) curves create a band that accounts for equipment contingencies. In addition, all of the cost effectiveness calculations reflected a two-year catalyst life to reflect a partial deactivation of OCSD’s oxidation catalyst after two years of operation. Although the CO emission levels were elevated and still in compliance with the proposed limit, the calculations were revised to reflect a two-year, instead of a three-year, catalyst life. The cost effectiveness ranges are illustrated in Figure 4 for digester gas engines and Figure 5 for landfill gas engines.

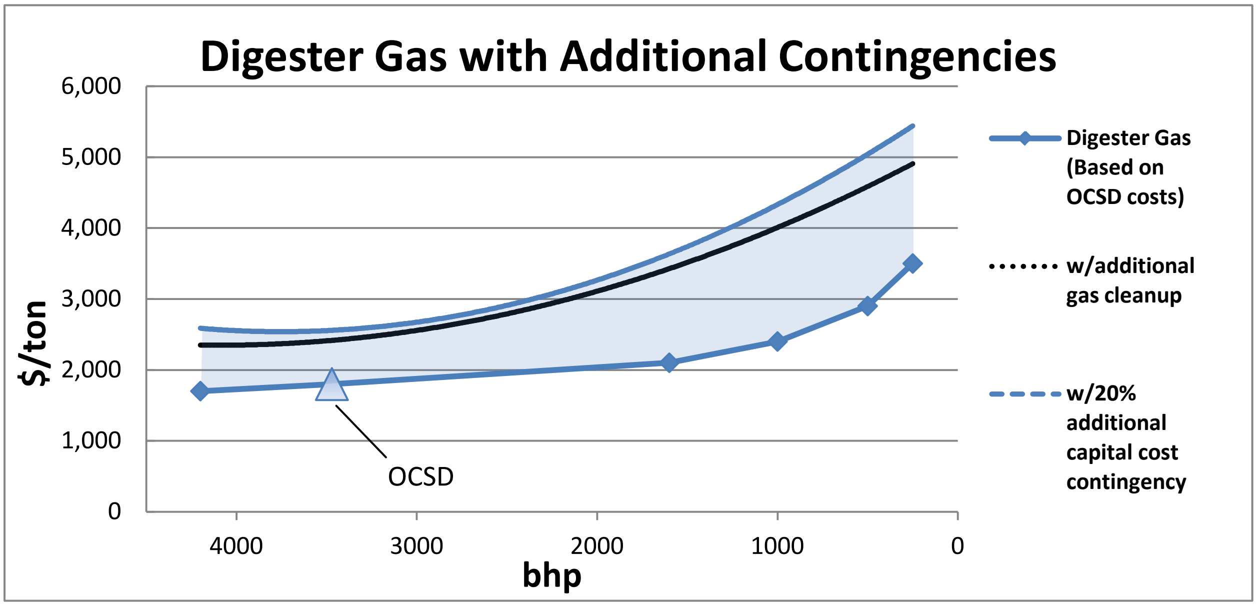


Figure 4. Cost Effectiveness for Digester Gas (Catalytic Aftertreatment)

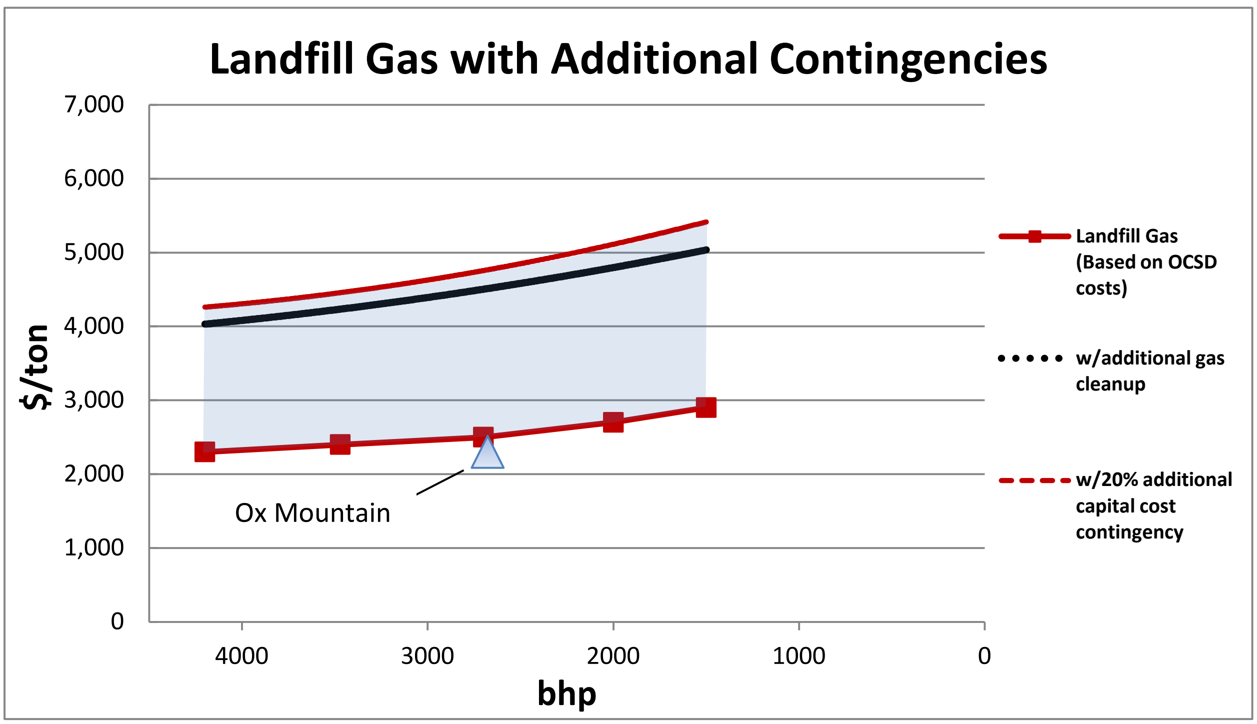


Figure 5. Cost Effectiveness for Landfill Gas (Catalytic Aftertreatment)

For catalytic control technology, the capital cost for the base level scenario on a per engine basis is expected to range from $417,000 for a 250 bhp engine to $2,706,000 for a 4,200 bhp engine. The capital cost range with added contingencies is $494,000 to

$3,147,000. These ranges represent the capital costs for the smallest engine to the largest in the biogas inventory.

The cost effectiveness estimates are within the costs presented to the Governing Board for past rulemakings. Digester gas and landfill gas engines of all sizes are shown to be cost-effective. The details of the cost effectiveness calculations with a detailed breakdown of the installation and operating costs are presented in the Technology Assessment (Attachments A and B).

INCREMENTAL COST-EFFECTIVENESS

Health and Safety Code Section 40920.6 requires an incremental cost-effectiveness analysis for Best Available Retrofit Control Technology (BARCT) rules or emission reduction strategies when there is more than one control option that would achieve the emission reduction objective of the proposed amendments, relative to ozone, CO, SOx, NOx, and their precursors. The proposed control option is biogas cleanup, with oxidation and SCR catalyst control, while the alternative control option is shutting down the engines, purchasing electricity from the grid, and flaring the biogas. To determine the incremental cost effectiveness, the calculated difference in the dollar cost between the two control options is divided by the difference in their emission reduction potentials.

The basis for the control options is the OCSD pilot study demonstration project engine (2500 kW). To calculate the cost to purchase the power from the grid, the present worth value (PWV) of the electricity produced by the engine is calculated using its size and its annual hours of operation (6,000 hours) at a nominal rate of $0.08 per kW-hr. The present worth calculation assumes a 4% interest rate and a 20 year program life. The present value of the operations and maintenance (O&M) costs is also factored (subtracted from the electricity costs) since these are costs that will be avoided if the engine is no longer in service. The engine maintenance costs are twice the upper value for a natural gas ICE ($0.014 per kW-hr). The total proposed project cost (PWV of OCSD engine with controls) is then subtracted from the PWV of the total project alternative project cost (purchasing electricity).

The emission reductions of the alternative project are calculated by using the net emissions of removing an engine from service and factoring the emissions from flaring and from a central power plant to replace the engine power produced. The emission reductions from removing the engine from service are calculated for NOx, VOC, and CO/7, using emission factors based on the current Rule 1110.2 compliance limits (at 6,000 annual operating hours and a 20 year program life). The flare emissions are calculated using the fuel consumption (permit limit) and existing (average limit) flare emission factors for NOx, VOC, and CO. The total emissions for flaring over 20 years are calculated for NOx, VOC, and CO/7. Next, the central power emissions are calculated using emission factors based on central power plant BACT emission standards. It was assumed that 50% of the power replaced would come from the central power plant. The emissions over 20 years were then calculated for NOx, VOC, and CO/7. The sum of the flaring and central power plant emissions are then subtracted from the engine emission reductions to obtain the net emission reductions of the alternative control option.

Finally, the emission reductions of the proposed control option are factored into the final calculation (from present rule limit to proposed rule limit at 6,000 annual operating hours over 20 years). The difference of the PWV of the alternative control option and the proposed control option is divided by the difference in the emission reduction potentials for both projects. If “a” is the alternative control option and “p” is the proposed control option, then the incremental cost effectiveness is:

$$(C_a – C_p) / (E_a – E_p) = \$757,100/\text{per ton}$$

The calculated value clearly indicates that the alternative control option is not viable when compared to the proposed controls.

CALIFORNIA ENVIRONMENTAL QUALITY ACT (CEQA) ANALYSIS

Pursuant to the California Environmental Quality Act (CEQA) and AQMD Rule 110, SCAQMD staff has reviewed PAR 1110.2 to identify the appropriate CEQA document for evaluating potential adverse environmental impacts. Because the proposed project consists of changes to a previously approved project evaluated in a certified CEQA document and none of the conditions described in CEQA Guidelines §15162 calling for preparation of a subsequent CEQA document would occur, staff has concluded that an Addendum to the December 2007 Final Environmental Assessment: Proposed Amended Rule 1110.2 – Emissions from Gaseous- and Liquid-Fueled Internal Combustion Engines (ICEs), prepared pursuant to CEQA Guidelines §15164, is the appropriate CEQA document for the proposed project. Pursuant to CEQA Guidelines §15164(c) an addendum need not be circulated for public review. However, upon completion, the Addendum as well as the February 2008 Final Environmental Assessment will be available to the public at AQMD Headquarters or by calling the AQMD Public Information Center at (909) 396-3600.

SOCIOECONOMIC ASSESSMENT

PAR 1110.2 would re-establish the concentration limits for biogas-fired engines for a later time, that is from 2012 to 20~~15/~~16. Furthermore, the universe of affected biogas-fired engines by PAR 1110.2 is currently at 55 engines, reduced from 65 engines evaluated as part of the 2008 amendments, which is a reduction of 14 percent of the total bhp.

The technologies for complying with the concentration limits have remained the same since 2008 and costs of these technologies have stayed relatively constant. According to the February 2008 Socioeconomic Report for Rule 1110.2, the 2011 present value (including capital, operating and maintenance costs) of SCR/Oxidation Catalyst/Biogas

Cleanup System for large biogas engines (>1,500 bhp) was $3.37 million over a 20-year period. The actual present value of a similar system (with catalyst replacement every three years) at OCSD was $3.09 million. Based on catalyst replacements every two years, AQMD estimates the present value of the same system to be $3.47 million.

The additional time for compliance and fewer affected engines would result in overall savings to the affected universe as a whole, compared to what was analyzed as part of the 2008 amendments. Therefore, given the fact that there are fewer engines to control and the control costs remained relatively constant compared to what was evaluated as part of the Socioeconomic Assessment conducted for the 2008 amendments to Rule 1110.2, the findings and conclusions of that analysis remain valid for this proposed amendment as well.

That 2008 Final Socioeconomic Assessment will be available to the public at AQMD Headquarters or by calling the AQMD Public Information Center at (909) 396-3600.

DRAFT FINDINGS UNDER CALIFORNIA HEALTH & SAFETY CODE SECTION 40727

California Health and Safety Code Section 40727 requires that prior to adopting, amending or repealing a rule or regulation, the AQMD Governing Board shall make findings of necessity, authority, clarity, consistency, non-duplication, and reference based on relevant information presented at the public hearing and in the staff report. In order to determine compliance with Sections 40727 and 40727.2 a written analysis is required comparing the proposed rule with existing regulations.

The draft findings are as follows:

Necessity: PAR 1110.2 is necessary to reduce emission limits from combustion equipment in order to meet federal and state ambient air quality standards for ozone and PM 2.5.

Authority: The AQMD obtains its authority to adopt, amend, or repeal rules and regulations from California Health and Safety Code Sections 39002, 40000, 40001, 40440, 40702, 40725 through 40728, and 41508.

Clarity: PAR 1110.2 has been written or displayed so that its meaning can be easily understood by the persons affected by the rule.

Consistency: PAR 1110.2 is in harmony with, and not in conflict with or contradictory to, existing federal or state statutes, court decisions or federal regulations.

Non-Duplication: PAR 1110.2 does not impose the same requirement as any existing state or federal regulation, and is necessary and proper to execute the powers and duties granted to, and imposed upon the AQMD.

Reference: In amending this rule, the following statutes which the AQMD hereby implements, interprets or makes specific are referenced: Health and Safety Code sections 39002, 40001, 40702, 40440(a), and 40725 through 40728.5.

COMPARATIVE ANALYSIS

Under Health and Safety Code Section 40727.2, the AQMD is required to perform a comparative written analysis when adopting, amending, or repealing a rule or regulation. The comparative analysis is relative to existing federal requirements, existing or proposed AQMD rules and air pollution control requirements and guidelines that are applicable to industrial, institutional, and commercial combustion equipment. A comparative analysis is not required if the District finds that the proposed rule does not impose a new emission limit or standard. The District makes that finding, since the 2012 limits are already existing and the proposed rule does not make it more stringent. Nevertheless, the District incorporates by reference the comparative analysis contained in the February 2008 Final Staff Report for PAR 1110.2, which is also updated below for changes.

National Emissions Standards for Hazardous Air Pollutants and New Source Performance Standards

Appendix F in the 2008 Final Staff Report for Proposed Amended Rule 1110.2 (February 2008) provides a detailed summary and comparison of the key elements of PAR 1110.2, the RICE NESHAP, and the NSPS. Appendix F is incorporated in this report by reference and is available at http://www.aqmd.gov/hb/2008/February/080233a.html. The proposed amendments of PAR 1110.2 are not in conflict with federal regulations.

AQMD Rules Applying to Stationary Gaseous- and Liquid-Fueled Engines

AQMD Rule 218 and 218.1 - Continuous Emission Monitoring Rules, which were amended on May 14, 1999, and May 4, 2012, respectively, set forth requirements for new, modified and existing continuous emission monitoring systems that include certification, development and implementation of a Quality Assurance/Quality Control Plan, recordkeeping, reporting, and performance specifications. PAR 1110.2 requires ICEs with required CEMS to comply with Rule 218 and 218.1.

AQMD Rule 401 – Visible Emissions, which was last amended on November 9, 2001, prohibits the discharge of emissions into the atmosphere from any single source for period or periods aggregating more than three minutes in any one hour which will cause: a dark or darker shade as that of a number 1 on the Ringelmann chart, as published by the United States Bureau of Mines, or of an opacity equal or greater than number 1 on the Ringelmann chart.

AQMD Rule 431.1 – Sulfur Content of Gaseous Fuels, which was last amended on June 12, 1998, prohibits the sale and use natural gas with a sulfur content exceeding 16 ppm. Rule 431.1 also prohibits the sale and use of the following gases with a sulfur content exceeding: 150 ppmv in landfill gas; 40 ppmv in refinery gas, sewage digester gas and other gases.

AQMD Rule 431.2 – Sulfur Content of Liquid Fuels, which was last amended on September 15, 2000, prohibits the purchase by stationary source end users of any diesel fuel with a sulfur content exceeding 15 ppm on and after June 1, 2004.

AQMD Rule 1303 - New Source Review Requirements, which was last amended on December 6, 2002, requires BACT, modeling and emission offsets for any new or modified source which results in an emission increase of any nonattainment air contaminant, ozone depleting compound or ammonia.

AQMD Rule 1401 - New Source Review of Toxic Air Contaminants, which was last amended on September 10, 2010, specifies limits for maximum individual cancer risk (MICR), cancer burden, and non-cancer acute and chronic hazard index (HI) from new, modified and existing permitted sources which emit toxic air contaminants (TACs) listed in Table I of Rule 1401. Although numerous TACs may be emitted from engines, formaldehyde, acrolein, methanol, and acetaldehyde account for essentially all of the mass emissions. PAR 1110.2 target pollutants are NOx, VOC and CO.

AQMD Rule 1470 - Requirements for Stationary Diesel-Fueled Internal Combustion and Other Compression Ignition Engines, which was amended on May 4, 2012, addresses primarily toxic diesel PM from new and existing, stationary, emergency and non-emergency, diesel engines, whereas Rule 1110.2 addresses only NOx, VOC and CO emissions.

AQMD Regulation XX - Regional Clean Air Incentive Market (RECLAIM) superseded many Regulation IV and Regulation XI rules for NOx and SOx for the largest facilities with an emission trading program that achieved equivalent emission reductions, but in a way to allow facilities flexibility in achieving emission reduction requirements for NOx and SOx by methods such as add-on controls, equipment modifications, reformulated products, operational changes, shutdowns, and the purchase of excess emission reductions. Facilities for which emission fee data for 1990 or subsequent year shows four or more tons per year of NOx or SOx, excluding certain exempt sources, are subject to this program. Regulation XX specifically identifies requirements for ICEs, in addition to other specific sources, which include monitoring, reporting and recordkeeping for NOx and SOx emissions. PAR 1110.2 would apply to VOC and CO emissions from IC Engines from these sources.

While only applicable to new electrical generating engines, the CARB 2007 Distributed Generation Regulation is discussed below.

CARB 2007 Distributed Generation Regulation

Beginning in 2007 CARB required new Distributed Generation (DG) units sold in the state to be certified by meeting emission standards that are at least equivalent or more stringent than those for large central power generating stations with BACT. The emission standards are applicable unless engines are not exempt from any District requirements. In addition, the regulation calls for currently permitted equipment to meet the more stringent emission standard by the earliest practicable date. Biogas fueled ICEs subject to the CARB regulation installed after January1, 2013 must meet the emission standards of large central power generating stations with BACT.

ATTACHMENT A

PAR 1110.2 PUBLIC COMMENTS AND RESPONSES

Technical Feasibility

Comment: There is no reliable hard data that documents the successful operation of a landfill gas to energy facility. SCR and gas cleanup for siloxane removal hasn't been proven.

Response: While the demonstration projects in our Basin focused on digester gas-powered biogas engine control systems, such systems are directly applicable to landfill gas-powered biogas engines. This holds true for the oxidation catalyst/SCR based system of the successfully completed pilot study by the Orange County Sanitation District as well as the other control technologies of the ongoing demonstration projects. The feasibility of biogas cleanup/oxidation catalyst/SCR-based controls on a landfill gas-powered biogas engine has been demonstrated by Ameresco at Ox Mountain Landfill in the Bay Area. Staff conducted a site visit to Ameresco's facility at Ox Mountain Landfill and verified that the equipment has operated successfully for almost three years with gas cleanup, oxidation catalyst, and SCR. With the exception of some operational challenges during commissioning and start-up, the equipment has been effective in meeting the proposed rule's emission limits. Ameresco's TSA system has never experienced a siloxane breakthrough and consistently removes siloxanes effectively. Gas cleanup for siloxanes has been in use at landfills is an established technology, as these systems are currently in use for the protection of landfill gas-fired turbines.

Comment: Flaring biogas is undesirable, but may be necessary if the costs of controls become too prohibitive.

Response: Staff agrees that the flaring of biogas is undesirable, especially since it is a renewable resource. However, if a facility decides to flare the biogas and purchase the lost power from a central power plant, the criteria pollutant impacts will be lower than operating the biogas engines and, although elevated, the greenhouse gas (GHG) will not be significant.

Comment: Staff should take into account and analyze the recent deactivation of OCSD's oxidation catalyst due to siloxanes in terms of added costs.

Response: Until staff receives and independently reviews the laboratory results, it is premature to say that siloxanes were the cause of the elevated emissions or conclude that the oxidation catalyst failed. Staff agrees that the elevated CO emissions above 100 ppmv are not what the facility is accustomed to and provided a reasonable cause for concern, but the emission levels were still well within compliance when the oxidation catalyst was removed from service. In spite of the uncertainty associated with the CO emission increase and to account for the potentially more frequent catalyst replacement needed, staff has adjusted the annual operating costs to reflect a 2 year life for the catalyst instead of a three year life. Even with the increased catalyst replacement frequency, the controls remain cost effective. Please note that Ox Mountain has also experienced a similar elevation of CO emissions during its three years of operating six engines, but the facility has not had to replace a catalyst throughout its entire operation due to deactivation.

Comment: Staff should conduct a site-by-site analysis of landfill lives for cost effectiveness. Some landfills are already closed and the 20 year life would not be realistic for any new equipment.

Response: There is an element of uncertainty associated with the closure of a particular landfill site. For example, one landfill site was scheduled for closure within the next few years. It is now our understanding that this same site may remain operating for several more years due to a decrease in the amount of waste deposited at that site. Also under consideration should be the fairly low cost-effectiveness of the proposed amendment. On this basis, a proposed project would still be marginally cost-effective with an equipment life much less than the assumed 20-year life. For example, the shortest term power purchase agreement from one of the affected private operators is nine years. Even with a nine year equipment life, the highest peak value of cost effectiveness is $13,100 per ton. This value is well within the cost effectiveness of previously adopted or amended NOx rules. For these projects there is a salvage value associated with the installed equipment, a value that was not accounted for in the proposed 20-year life project. Ultimately it is a business decision unique to the particular facility operator to shut down the site prior to rule implementation in 2016~~5~~, install the proposed control equipment, opt for one of the alternate control options (e.g., flex energy), or burn the fuel in other existing equipment (e.g., boilers and flares), if available.

Comment: Stakeholders have not received any substantial information and data regarding Ox Mountain's ability to continue to comply with the proposed emission limits.

Response: Staff conducted a site visit to the facility in April and received a wealth of information from the facility operators. This information is provided in the Technology Assessment. In addition, staff has requested more complete CEMS data and is currently awaiting its receipt. Upon receipt and analysis, Staff will make the information available to the stakeholders.

Comment: SCR technology is not scalable to smaller engines.

Response: Based on communication with technology vendors, SCR systems are scalable to the engines of all sizes, including the smallest in the biogas engine inventory. These vendors have been producing catalytic controls for over 2 decades on a wide variety of equipment and for engine sizes within the scope of this rule amendment. The control systems in SCR units are a standard size and are provided at a fixed cost. The catalyst volume is dependent on the horsepower of the engine and the outlet flow produced, but is a smaller part of the total price for smaller engines. The catalyst price and housing size actually begins to increase for higher horsepower engines and flows since more catalyst blocks are required. SCR systems have been installed on a wide range on engine sizes, including the size range of the biogas engines subject to this regulation.

Comment: Commercial, cost-effective technologies are not available.

Response: In staff's Technology Assessment, Oxidation Catalyst/SCR with gas cleanup has been identified as feasible, cost-effective technology. Once biogas is cleaned the catalysts perform at the same level as natural gas-fired engines.

Comment: Biogas is not natural gas and biogas engines should not be subject to the same emission restrictions as natural gas engines.

Response: The difference between biogas and natural gas is the methane content and, hence, the BTU level. Installations exist today that convert biogas into high BTU gas that can actually be injected into the natural gas pipeline. There are also gas cleanup systems in the District that currently clean landfill gas for powering gas turbines. Staff feels that when properly cleaned, biogas can run an engine with controls and should be subject to the same requirements as those for natural gas engines, especially when the emissions from current biogas engines are 55 times higher than those of central power plants.

Operational/Compliance

Comment: NOx excursions above the compliance limit will be expected at landfill sites. Maintaining the efficiency correction factor (ECF) would help to accommodate these excursions.

Response: Staff's proposal of using a longer averaging time will actually benefit a facility better than using the ECF. For example, an engine with an ECF of 1.25 will have a NOx limit of 13.75 ppmv. The longer averaging time proposed in the rule will aid in addressing spikes that are much higher than 13.75 ppmv, as long as the equipment is consistent in meeting lower mass emissions.

Comment: The operation of the NOxTech does not necessarily require an Air-to-Fuel-Ratio Controller (AFRC) to function properly. A rule provision should be added to make an allowance for an AFRC to be optional when operating the NOxTech.

Response: The rule allows for alternative controls with an equivalent environmental benefit to be maintained, approvable by the Executive Officer. On this basis, the use of the NOxTech, provided that it meets the rule limits, is potentially approvable.

Comment: Rule 1110.2 should be amended to make the breakdown provision consistent with that in Rule 430 in that a breakdown that results in the violation of any rule or permit condition be reported to the District within one hour of such event.

Response: The reporting provisions in Rule 430 and in Rule 1110.2 are both clear in classifying breakdowns that result in the violation of a rule or permit condition and those that result in excess emissions that violate a rule or permit condition. An operator has to be mindful of other rule or permit conditions, including those under Rule 430.

Comment: A shutdown provision should be added to the rule in addition to the 30 minute start-up exemption.

Response: Staff agrees with the commenter and has added the shutdown provision in the staff proposal to allow for proper cool down of engines and control equipment.

Comment: To remain in compliance, oxygen set points can be adjusted before going out of compliance. But the penalty incurred for this preventative measure is to return to a more frequent portable analyzer testing schedule.

Response: Staff agrees with the commenter and has included in the staff proposal the allowance for oxygen set point adjustments without returning to a more frequent portable analyzer testing schedule if the engine is in compliance before and after the set point adjustment.

Comment: When adhering to a portable analyzer testing schedule, some tests will coincide with a source test. A source test followed by a portable analyzer check at the same time is unnecessarily repetitive.

Response: Staff agrees with the commenter and has made a clarification in the Staff Report to allow source test results to be used in lieu of concurrently scheduled portable analyzer checks.

Comment: A clarification is needed to allow for the temporary removal of a catalyst for up to four hours after engine start-up following an engine overhaul or major repair requiring removal of a cylinder head. Oil and particulate contaminants from engine work can ruin a catalyst if it is operating during start-up.

Response: Staff agrees with the commenter and has made a clarification in the Staff Report to allow the temporary removal of a catalyst under the exemption provisions of Rule 1110.2(h)(11).

Comment: For operators of lean burn engines with low CO emissions, the currently required quarterly portable analyzer checks are unnecessary. Biannual source tests would be sufficient for compliance.

Response: The application of portable analyzer checks on a quarterly basis was the result of an extensive rule making process. The commenter will need to provide data to show that biannual source tests would be sufficient.

Comment: RECLAIM quarterly certification of emissions (QCER) reports are due within 30 days of the end of a quarter, but the Rule 1110.2 Inspection and Monitoring (I&M) reports are due within 15 days of the end of a quarter. RECLAIM facilities would like the submittal of the two reports to coincide at 30 days.

Response: It is not surprising that different rules will have different reporting requirements. These differences extend to both the content and submittal schedule of the reports. Unless the commenter can demonstrate the Rule 1110.2 reporting schedule should be lengthened, the current schedule will remain intact.

Comment: The proposed 24~~12~~ hour averaging time should be applied to CO as well as NOx.

Response: Staff agrees and has modified the staff proposal to extend the longer averaging time option to CO.

Comment: The proposed lowering of the CO and VOC emission levels for new distributed generation (DG) engines to the CARB DG standard is unattainable. Current, on-going projects that are barely capable of meeting the current rule standards will not be able to meet the proposed levels. Some new projects will have to cease, allowing old, grandfathered engines to continue to operate. With the San Onofre plant possibly shutting down, there could be significant implications with distributed generation in California.

Response: Based on the response from industry and the current status of the technology, staff will retain the current standard, but will consider lowering the standard to the CARB level in the future.

Compliance Schedule

Comment: The two year implementation deadline is not realistic for the design and construction of catalytic controls, especially for public agencies.

Response: Staff has revised its proposal to extend the compliance schedule to ~~3 and 4~~ three and a half years beyond the July 1, 2012 date, with up to 2 additional years for operators under long term fixed price power purchase agreements entered into before the February 1, 2008 amendments and extending beyond the January 1, 2016 compliance date with the payment of the compliance flexibility fee.

Comment: Other potential technologies seem infeasible with the current two to three year implementation schedule since they have not been proven to be effective.

Response: The Technology Assessment is providing ample evidence about the feasibility of controlling emissions from biogas engines through an oxidation catalyst/SCR control system in conjunction with a biogas cleanup system. The proposed ~~three to four~~ three and a half year implementation schedule will allow for additional technology demonstration projects to complete and provide stakeholders with more choice and enough time to allocate funds, permit, construct, and install the equipment.

Comment: The compliance schedule should be conditional upon meeting certain technology demonstration goals by keeping the Technology Assessment open, thus allowing the technology to prove itself before committing to a schedule.

Response: Staff will commit to continue the technology review/implementation process and report back to the Stationary Source Committee beginning no later than~~by~~ July 1, 2013 to assure that the schedule for compliance is reasonable and to make appropriate recommendation on potential rule changes if necessary.

Cost Effectiveness

Comment: The cost analysis should be conducted using dollars per kW hour. This is more relevant to an operator's decision making to justify the project. The Interim Technology Assessment committed to analyzing costs using this metric.

Response: While it is difficult to perform this type of analysis since every single facility and operator affected by the proposed amendments is unique, Staff did calculate costs in dollars per kW hour in its analysis across the range of engine sizes with considerable contingencies. The fact remains that the environmental benefits are not reflected at all in a cost per kW hour calculation. As operators make decisions based on dollars per kW hour, our Governing Board has to make decisions based on the cost per ton of pollutants removed.

Comment: Existing gas cleanup equipment was used in OCSD and the costs for a brand new system should be included in AQMD's cost analysis.

Response: OCSD used its existing compressors and chillers for its gas cleanup. Other operators also have similar existing equipment. However, Staff has applied a 20% contingency to the equipment capital costs to account for the necessity of some facilities to install brand new equipment, such as compressors and chillers. These costs are reflected in Staff's cost effectiveness analysis.

Comment: The costs are based on OCSD low siloxane levels. There is no analysis for facilities with much higher siloxane loads, such as in landfill applications.

Response: OCSD changed its media three times during its year-long demonstration project. The cost analysis has also accounted for much more frequent carbon media change-outs (monthly), to account for scenarios with higher siloxane loads. This will obviously drive up the operational costs and is reflected in Staff's analysis as a cost contingency.

Comment: The emission reductions that Staff calculated for Ox Mountain are not considering the actual emission levels and overstate the emission reductions.

Response: For rulemaking, it is the standard practice to calculate emission reductions from rule or permit limits to the proposed limits. Actual emission levels and source tests are "snapshots" of a moment in time and, although compliant, may not accurately reflect the emissions for any other given time period. Please do note that if one considers the better than expected performance of the control technologies, arguably there are additional reductions that can be claimed above and beyond the proposed rule limits. Therefore, staff believes that calculating emission reductions from current limits to future rule limits, for the purposes of estimating cost effectiveness, is a reasonable approach.

Comment: Plants with less engines and less capacity will pay a much higher capital cost for gas cleanup.

Response: The size of the gas cleanup system is dependent on the overall fuel flow rate of the gas that will be used by the engines. Smaller fuel flows will require smaller media vessels. The operating costs will depend on the siloxane load and how often media change-outs are required.

Comment: Staff has not incorporated the costs submitted by the affected facilities into its cost effectiveness analysis.

Response: District staff solicited cost information from all the affected biogas facility operators and received detailed costs for half of these facilities. Based on the costs provided by the twelve facilities and applying emission reductions from existing to proposed rule limits, the current cost effectiveness range as submitted by the twelve facilities using the DCF model is \$2,700 to \$50,100 per ton of NOx, VOC, and CO/7. This is a wide range and is difficult to normalize based on the wide variety of cost assumptions submitted. OCSD's calculated cost effectiveness, including additional contingencies, amounted to \$2,600 per ton. It should be noted that the OCSD's cost effectiveness is based on actual data, not estimated data by the twelve facilities. A cost effectiveness of \$30,000 per ton roughly signifies the upper limit for rules presented to the AQMD Governing Board, based on past rulemakings. All of the cost submittals contained contingencies of varying degrees, and others added inflation rates to the cost estimates. These cost components have never been used in any of the past AQMD cost effectiveness analyses. The cost effectiveness of two facilities (\$48,200 and \$50,100 per ton) illustrates the effect of excessive contingencies added to the capital and operating costs. One facility had capital contingencies up to 50%, in addition to its project design and management contingencies. Some of the equipment costs are significantly higher than those provided by vendors, even with contingencies added. OCSD's operating costs in its final report were \$58,950, while some of the others facilities' were orders of magnitude higher (as high as over 10 times). These excessively high contingencies and operating costs are inappropriate for a cost effectiveness analysis that has a reference point based on actual cost data. Even though the twelve facilities provided their own cost data, inflation rates, and contingency factors, only the two aforementioned facilities' cost effectiveness went above the Board-accepted cost effectiveness for recently amended

AQMD rules. Taking this into account as well as the cost effectiveness analysis based on actual cost data clearly indicates that the staff proposed rule amendment is cost effective.

Comment: No costs for additional maintenance for the gas cleanup system and catalyst controls as well as costs for lost electricity during maintenance were provided for Ox Mountain, which can drive up costs.

Response: Gas cleanup generally results in extending the engine's operating cycle and reducing the maintenance cycles and frequency during which engines must be taken out of operation and undergo expensive repairs. Longer operating cycles and reduced maintenance translate into more power produced and reduced operating costs. These cost savings were not identified by the commenter. Staff has added contingencies in its cost analysis to cover some of the potential costs identified by the commenter. With the contingencies added, the cost effectiveness is well within (by a factor of 6) the rough upper bound of $30,000 per ton, based on previous AQMD rulemakings. Consequently, even if costs for maintenance and reduced power production nominally increase for a particular installation adjusted with the previously mentioned cost savings, the resulting cost effectiveness would be well within the upper bound value and thus, still cost effective.

Space Limitations

Comment: The space limitations at some facilities would make it impossible to add oxidation catalyst and SCR controls to the engines.

Response: Catalyst manufacturers and installers have found innovative ways to design and construct structures and piping to accommodate varying configurations. For example, OCSD's project involved the construction of an elevated platform outside of the engine building to allow for vehicle traffic underneath. Other installations use elevated supports, roof-mounted supports, and even wall-mounted supports where plot space is very limited.

Financing Control Equipment

Comment: Existing power purchase agreements (PPAs) make it impossible to make any capital expenditures on control equipment. Any modifications would be economically infeasible and would likely lead to flaring.

Response: Staff has requested the PPAs from those affected for review by District Counsel, per the recommendation from members of the Stationary Source Committee at its April 2012 meeting. To date, staff has not received any PPAs from the affected facilities. It should be noted that the ongoing rule development process regarding the biogas engines was initiated well before the 2008 amendments, which provided the operators with more than adequate time to revise their PPAs prior to the future effective dates. Despite this, staff is proposing an alternate compliance option for these affected facilities, which will provide up to two additional years for compliance beyond the January 1, 2016 compliance date, with the payment of a compliance flexibility fee. Only operators that entered into power purchase agreements prior to the February 1, 2008 amendments and that extend beyond the January 1, 2016 compliance date are eligible to benefit from the alternate compliance option.

Comment: The stakeholders need help in achieving a legislative fix to provide additional financial incentives for biogas energy projects.

Response: The AQMD will be a willing participant in the support of legislation that will provide additional financial incentives for biogas energy projects and has already taken support position on several pending legislations.

Comment: Current State legislation prohibits any landfill gas to pipeline projects. The stakeholders also need District support in helping stakeholders reach this goal.

Response: The AQMD will also be a willing participant in support of allowing stakeholders to inject clean landfill gas into the gas pipeline, provided it is cleaned up to reasonable specifications established by CPUC or State law.

GHG Impacts

Comment: Staff needs to consider criteria pollutant emissions that are offset from operating biogas engines and not flaring and purchasing electricity from the central power plants.

Response: Staff has considered the tradeoffs between generating electricity with biogas engines meeting current emission limits and central power plants. While increased flaring of biogas results in increased electricity generation from central plants to meet demand, the resulting criteria pollutant emissions impact from both central power plants and biogas flaring would be less than current engine emissions and, for GHG emissions, would be slightly higher. Staff has analyzed the impact of potential increased flaring in the staff report and in the Technology Assessment.

Comment: Staff needs to acknowledge the benefit of gas to energy projects as better overall for GHG emissions than flaring.

Response: AQMD staff acknowledges the benefits of biogas to energy projects. Since the South Coast is a non-attainment area for ozone, achieving criteria pollutant reductions is a priority for AQMD and CARB. In our GHG analysis, it is clear that the criteria emissions from flaring are lower than from biogas ICEs. Staff, however, is mindful that flaring is undesirable and understands the importance of maintaining the productivity of biogas to energy projects. Since biogas engines pollute significantly more than their natural gas counterparts and central power plants, it is staff's desire to decrease biogas ICE emissions by requiring controls which are both feasible and cost effective. Given the region's extreme non-attainment status with respect to the 8-hour ozone standard and non-attainment status with respect to the PM2.5 standards, the superior criteria pollutant reduction benefits (especially in NOx) of the staff proposal (even with increased flaring) will more than compensate for the slight disbenefit in GHG emissions.

ATTACHMENT G

SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT

Assessment of Available Technology for Control of NOx, CO, and VOC Emissions from Biogas-Fueled Engines

Draft Final Report

August 2012

Executive Officer
Barry R. Wallerstein, D.Env.

Deputy Executive Officer
Planning, Rule Development, and Area Sources
Elaine Chang, DrPH

Assistant Deputy Executive Officer
Planning, Rule Development, and Area Sources
Laki Tisopulos, Ph.D., P.E.

Planning and Rules Manager
Planning, Rule Development, and Area Sources
Joe Cassmassi

Author:	Kevin Orellana – Air Quality Specialist
Reviewed by:	Gary Quinn, P.E. – Program Supervisor William Wong – Principal Deputy District Counsel
Technical Assistance	Alfonso Baez, M.S. – Program Supervisor Wayne Barcikowski – Air Quality Specialist

TABLE OF CONTENTS

INTRODUCTION

Rule 1110.2 establishes emission limits of NOx, VOC, and CO for stationary, non-emergency gaseous- and liquid-fueled engines, including the 55 engines in this source category, that are fueled by landfill or digester gas (biogas). The emissions from biogas engines amount to approximately 1.3 tons per day of NOx, 0.8 tons per day of VOC, and 25.6 tons per day of CO.

Rule 1110.2 was amended on February 1, 2008 to lower the emission limits of natural gas and biogas engines to BACT levels for NOx and VOC and to levels close to BACT for CO. The limits for natural gas engines at or above 500 bhp took effect on July 1, 2010, while those for natural gas engines below 500 bhp took effect on July 1, 2011. Biogas engines were given until July 1, 2012 to comply with the new limits.

Table 1. Current and Future Biogas Engine Emission Limits (ppmvd @15% O_2)

	NOx	VOC	CO
≥ 500bhp	36 x ECF*	250 x ECF* (digester) 40 (landfill)	2000
< 500 bhp	45 x ECF*	250 x ECF* (digester) 40 (landfill)	2000
Future limits[1]	***11***	***30***	***250***

*ECF is the Efficiency Correction Factor

[1] The "future" limits are those that were originally scheduled to go into effect July 1, 2012, but did not go into effect, as explained below.

The future emission levels in Table 1 are based on BACT limits for lean-burn natural gas engines, which in g/bhp-hr are 0.15 for NOx, 0.6 for CO, and 0.15 for VOC. The current BACT limits for biogas engines are much higher. Expressed in g/bhp-hr, they are 0.6 for NOx, 2.5 for CO, and 0.8 for VOC. Figure 1 highlights this difference.

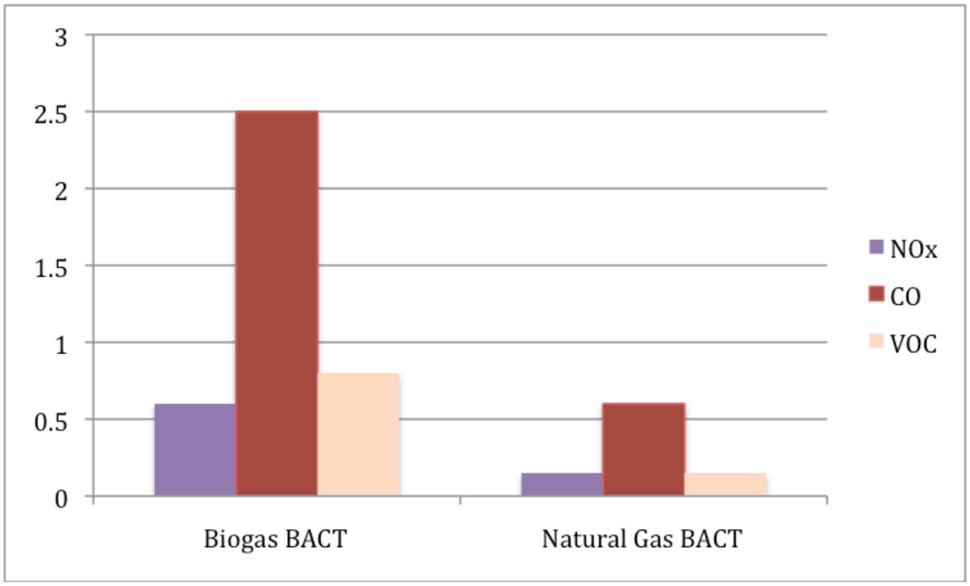


Figure 1. Biogas vs. Natural Gas BACT in g/bhp-hr

The BACT limits for lean-burn natural gas engines have been in effect for many years and many installations are complying with these limits by way of oxidation catalysts for CO and VOC control and selective catalytic reduction (SCR) for NOx control.

The amendment and adopting resolutions of Rule 1110.2 in 2008 directed staff to conduct a Technology Assessment to address the availability, feasibility, cost-effectiveness, compliance schedule, and global warming gas impacts of biogas engine control technologies and report back to the Governing Board no later than July 2010. Immediately after the 2008 amendment, staff began work on the Technology Assessment and followed the progress of several technology demonstration projects.

1. *OCSD* *(Orange County Sanitation District)*. A year-long pilot study utilizing a digester gas cleanup system (non-regenerative) and catalytic oxidation with selective catalytic reduction.

2. *EMWD* *(Eastern Municipal Water District)*. Two selective non-catalytic reduction technologies applied to water and wastewater treatment applications. One technology (NOxTech) was installed at a pumping station with three natural gas-fired engines. The other technology utilizes fuel cells to produce power from digester gas at two of its wastewater treatment facilities.

3. *IEUA (Inland Empire Utilities Agency)*. Fuel cells have been installed at this digester gas facility to eventually replace the IC engines currently installed.

4. *Ox Mountain*. This installation in the Bay Area uses biogas cleanup, catalytic oxidation, and SCR to produce power from landfill gas. The technology is similar to OCSD's in its post combustion after treatment, but uses a regenerative siloxane removal system to clean the landfill gas.

In July 2010, staff presented to the Governing Board an Interim Technology Assessment which summarized the biogas cleanup and biogas engine control technologies to date and the status of on-going demonstration projects. Due to the delays caused by the permit moratorium in 2009, the release of another report was recommended upon the completion of these projects. The Interim Technology Assessment concluded that feasible, cost-effective technology that could support the feasibility of the July 2012 emission limits is available, but that the delay in the demonstration projects would likely necessitate an adjustment to the July 1, 2012 compliance date of Rule 1110.2.

The proposed amendments for Rule 1110.2 provide an adjustment to the July 1, 2012 compliance date. Since July 2010, District staff has received ample evidence in support of the feasibility of biogas engine control technology and the feasibility of the compliance limits to complete the Technology Assessment. This Final Technology Assessment discusses the technologies pertinent to biogas engines for complying with these emission limits.

BIOGAS CLEANUP

For natural gas engines, the use of catalyst after-treatment is an effective method for pollutant control. However, Rule 1110.2 did not lower the emission limits for biogas engines at the same time as natural gas engines because the same catalyst controls for natural gas engines would experience fouling when exposed to the combustion products of biogas. It was learned that the cause of the catalyst fouling was due to a specific impurity in the gas stream. These impurities are now known as siloxanes.

In the 2010 Interim Technology Assessment, the impacts of siloxanes were highlighted and evaluated in terms of facility-specific levels and control costs. The conclusion was that by installing an appropriately designed biogas cleanup system, an engine along with its post-combustion control system can function properly.

A prime concern for many biogas engine operators is the quality of the fuel going into the engines. Biogas, whether coming from a wastewater treatment plant digester or from a landfill, has many impurities, including but not limited to sulfur-containing compounds and siloxanes, that require some sort of treatment. If left untreated, raw biogas can damage engine components that will result in more maintenance and ultimately, reduced longevity of an engine. Siloxanes crystallize at elevated temperatures and can become deposited even in fuel lines. Upon combustion, siloxanes oxidize and more commonly become deposited on engine parts (pistons, piston sleeves, and valves) as silicon dioxide (SiO_2). As a result, more frequent major maintenance on engines is required so that these deposits can be cleaned up from within the engine. These major repairs involve the removal of the engine head to access the internal valves and piston shafts. Failure to perform this kind of maintenance can result in catastrophic damage to an engine. The pretreatment of biogas is even more critical with the employment of catalyst-based after-treatment technologies downstream from the engines. If left untreated, these siloxane impurities can negatively affect the catalysts. The catalyst active sites can become masked by the deposition of the silica, therefore reducing the efficiency of the entire catalyst for pollutant removal.

Since the release of the Interim Technology Assessment and the installation of several biogas cleanup systems in the basin, it has been established that biogas cleanup cannot consist of siloxane removal only. Depending on the source of the raw biogas, some facilities have biogas profiles that contain varying levels of other pollutants, such as VOCs and sulfur compounds. Also, with the installation of fuel cells and gas turbines operating on biogas in the basin, the fuel specifications for these sophisticated units are extremely stringent for impurities. Biogas entering these systems must be completely cleaned of many impurities to guarantee proper performance.

Some facilities currently have practically no gas cleanup while most others employ some sort of gas cleanup for improved engine maintenance. On the other hand, a few facilities already employ a complete biogas cleanup system for protection of post combustion catalysts or turbines. Many facilities often utilize a typical cleanup system that results in moisture and particulate removal only. The previously mentioned demonstration project at the Orange County Sanitation District (OCSD) utilized the facility's existing compressors and chillers, while relying on a single activated carbon vessel as the sole source for siloxane removal. This digester gas cleaning system (DGCS) was installed (supplied by Applied Filter Technology) to remove contaminants from the digester gas before combustion and the potential for carbon media breakthrough was routinely monitored throughout the pilot study. Depending on the existing level of contaminants, some facilities may have to install complete, skid-mounted gas cleanup systems that can include water and particulate removal filters, sorbent vessels for H_2S and siloxane removal, compressors, chillers, coalescing filters, and vessels for VOC and sulfur species removal if necessary.

As described in the Interim Technology Assessment, there are two types of siloxane removal systems: regenerative and non-regenerative. Regenerative siloxane removal systems do not require constant removal of the sorbent material from the vessels. The vessels are set up in pairs and while the media in the first vessel is regenerated using a heated purge gas the second vessel handles the siloxane cleanup load. The regeneration cycle then switches to the second vessel when it nears its removal efficiency limit, while the first vessel now handles the gas cleanup.

The regenerative siloxane removal system at Ox Mountain Landfill is the only installation that currently uses this type of system for the protection of a post-combustion catalyst on a landfill gas-fired engine. Ox Mountain Landfill is located at Half Moon Bay, CA which is within the Bay Area Air Quality Management District's (BAAQMD) jurisdiction. The landfill gas to energy site (operated by Ameresco) has six GE-Jenbacher engines, each rated at 2677 bhp, that are fired on landfill gas. All six engines have been retrofitted with oxidation catalysts, while one of the engines also has an SCR system. The gas cleanup system with regenerative siloxane removal processes the gas for all the engines. It employs a Temperature Swing Adsorption (TSA) regenerative siloxane removal system manufactured by GE-Jenbacher. Eight pairs of adsorption beds (16 total vessels) using regenerative activated carbon are employed at this installation. AlO_2 is an alternate media that is used as other locations. Electric coils in the vessel annular space heat the carbon media while clean biogas is flushed through the beds as a purge gas. The purge gas is then combusted by a small, enclosed flare. At Ox Mountain, eight vessels are actively removing impurities while the other eight are being regenerated. The parasitic load of the TSA system is obviously higher when actively heating the vessels, but it is about 5% of the total plant's output. The gas cleanup and oxidation catalyst/SCR was commissioned in 2009 and has shown to be very effective in the removal of siloxanes from the landfill gas. Performance data from 2009 to 2011 shows that the system is removing between 95 and 99 percent of inlet siloxanes (inlet between 7 and 10 ppmv with reported spikes between 25 and 50 ppmv), while no siloxane breakthrough has ever occurred at this facility. The gas is tested periodically, while carbon media and engine samples are also analyzed. Ox Mountain's TSA media requires a complete replacement around every twelve months, but some installations can go longer before media replacement. Every installation will have its own unique gas profile, so the regeneration cycles will be specific for every location and will take start-up time and testing to optimize. The engines at Ox Mountain have also enjoyed the benefit of less frequent maintenance, and can run for much longer between major overhauls.

Non-regenerative siloxane removal systems require periodic replacement of the sorbent material (activated carbon or silica gel) once it is spent. Additionally, the use of two beds is more beneficial in that one bed can still be used while the other is recharged with fresh sorbent and vice versa. These systems are sized to handle the site-specific flow rate into all the facility's biogas engines and the siloxane load. Larger vessels are required for higher flow rate applications and a higher frequency of sorbent replacement is required for biogas streams with higher levels of siloxanes. A redundant dual-bed system enables the handling of intermittent spikes.

The following two tables (Table 2 and Table 3) are updates from the Interim Technology Assessment regarding catalyst performance with the protection of biogas cleanup with non-regenerative siloxane removal systems located both inside and outside of SCAQMD jurisdiction. All of the systems have been successfully operating with varying levels of biogas and the oxidation/SCR catalysts have been protected.

The demonstration project at OCSD has proven that a non-regenerative siloxane treatment system can condition biogas and protect biogas engines and post combustion catalysts. The gas cleanup system removed siloxanes, VOCs, and sulfur compounds effectively without any breakthrough to the engines. An added benefit was realized in that there was a reduction in the engine maintenance due to the cleaner biogas that was being combusted. Furthermore, the result was a cost savings for engine maintenance, increased engine uptime, and longer maintenance intervals. The OCSD demonstration project saved $43,547 in engine maintenance costs annually with the use and careful monitoring of the gas cleanup system. Additionally, the gas cleanup system from its catalytic oxidizer pilot study in 2007 is still in operation today based on the performance improvements to the engine and the reduced maintenance costs.

With the demonstration project at OCSD completed and the installation at Ox Mountain in its third year, the employment of both regenerative and non-regenerative siloxane removal systems for the protection of post-combustion catalyst has been proven to be feasible. Performance data from both installations demonstrates effective siloxane removal for both digester and landfill gas applications.

Table 2. Non-Regenerative Siloxane Removal Systems Located in SCAQMD

System	Type of Biogas	Size (SCFM Biogas)	Combustion Device	Natural Gas Blend in Combustion Device	Catalyst(s)	Startup Year	Operating History	Status	Comments
Orange County Sanitation District	Digester Gas	850	IC Engine	10% Max	Oxidation	2006	Engine operation has been normal	Operating	Similar system tested in pilot study in 2010
Brea Parent 2007, LLC	Landfill Gas	3,000	IC Engine (3)	None	Oxidation	2006	Engine operation has been normal	Operating	Similar system will be used on new turbine plant with Oxidation/SCR catalysts
City of Industry	Landfill Gas	267	IC Engine	73%+	SCR and Oxidation	2005	Seasonal Operation	Use of biogas ended 2007	Methane content too low
UCLA	Landfill Gas	3,472	Gas Turbine	78%+	SCR and Oxidation	1994	Turbine operation has been normal	Operating	
LADWP Scattergood Generating Station	Digester Gas	5,555	Boiler (2)	89%+	SCR and Oxidation	2001	Boilers have been in normal operation	Operating	

Table 3. Non-Regenerative Siloxane Removal Systems Located Outside of SCAQMD

System	Type of Biogas	Size (SCFM Biogas)	Combustion Device	Natural Gas Blend in Combustion Device	Catalyst(s)	Startup Year	Operating History	Status	Comments
Carson Cogen (Elk Grove, CA)	Digester Gas	2,500	Gas Turbine	75%	SCR	1996	Turbine operation has been normal	Operating	Digester gas now is further cleaned and transferred via natural gas pipeline to another power plant
Bergen County Utilities Authority (NJ)	Digester Gas	300~~800~~	IC Engine	10-20%~~None~~	Oxidation	2008~~2~~	IC Engine operation was normal	Operating~~Awaiting Status~~	CO limit is 27.1 ppmv, so more frequent catalyst replacements are required
City of Eugene Wastewater Treatment Plant	Digester Gas	240	IC Engine	None	Oxidation	2004	IC Engine operation has been normal	Awaiting Status	

CATALYTIC OXIDATION/SELECTIVE CATALYTIC REDUCTION

A proven and effective means for CO, VOC, and NOx control among natural gas fueled lean-burn engines is catalytic oxidation with selective catalytic reduction (SCR). If the raw biogas is cleaned sufficiently and effectively, there is no danger of fouling any post combustion catalyst by siloxane deposition.

Catalytic oxidation removes CO and VOC upon its contact with the catalyst. Oxidation catalysts contain precious metals that react incoming CO and VOC with oxygen to produce CO_2 and water vapor. Reductions greater than 90% in CO and VOC emissions are typical with this technology.

SCR can be used with lean-burn engines since the higher oxygen concentrations in the exhaust preclude the use of less costly nonselective catalytic reduction (NSCR or three-way catalysts). SCR requires the injection of urea to react with the NOx in the engine's flue gas, and is very effective in its removal. The SCR catalyst promotes the reaction of ammonia with NOx and oxygen, with water vapor and nitrogen gas being the end products.

The demonstration project at OCSD has shown with certainty that this combination of post combustion systems (oxidation catalyst and SCR) is capable of handling treated biogas combustion exhaust for multi-pollutant control. The District issued a grant to OCSD in 2009 (*SCAQMD Contract #10114*) to support the pilot test study of Engine No. 1 (in Fountain Valley) with a catalytic oxidizer/SCR with digester gas cleanup, and the operation of the pilot study was granted a Permit to Construct/Operate for an Experimental Research Project by SCAQMD (Application Number 497717) in November 2009. The construction and installation of the pilot study equipment commenced in October 2009; the pilot study testing officially began on April 1, 2010 and officially ended on March 31, 2011. A continuous emission monitoring system (CEMS) was used for analysis of NOx and CO emissions. The sampling methods for several other pollutants are listed in Table 4.

Table 4. Sampling Methods for Pollutants in OCSD Pilot Study

Pollutant	Sampling Method
CO	CEMS, Portable Analyzer, SCAQMD Method 100.1
VOC	SCAQMD Methods 25.1/25.3
NOx	CEMS, Portable Analyzer, SCAQMD Method 100.1
Aldehydes	Modified CARB Method 430, SCAQMD Method 323 (Formaldehyde)
Free Ammonia (Ammonia slip)	Modified SCAQMD Method 207.1 and Draeger® tubes

The results of the pilot study are as follows:

1. NOx emissions averaged around 7 ppmv, well below the proposed rule limit of 11 ppmv by over 35 percent.
2. VOC emissions averaged around 3.6 ppmv, well below the proposed rule limit of 30 ppmv by 88 percent.
3. CO emissions averaged around 7.5 ppmv, well below the proposed rule limit of 250 ppmv by 97 percent.

The maximum VOC level reached was around 5 ppmv, while the maximum CO level reached was 42 ppmv. The results were based on a 15-minute averaging time, per the current rule requirements. There were some NOx excursions during the testing period, however, and these accounted for around 4% of the total 15-minute measurement periods, using both valid and invalid data. Exceedances that were attributed to engine start-up (first 30 minutes), operational issues (breakdowns), and system adjustments were excluded and labeled invalid. Only validated data was used to account for the excursions, and these accounted for 0.9% of the total time periods.

Data from the OCSD demonstration project indicates that the emission control system reduces emissions of air toxics. The gas cleanup system removes acid gases, sulfur compounds, volatile air toxics, including aromatic and chlorinated organic compounds, and particulates that contain toxic compounds. OCSD took samples of digester gas before and after the gas cleanup system. The test program analyzed 66 organic compounds including 16 air toxics. OCSD test results indicate that concentrations of air toxic compounds are reduced, non-detectable, or not changed. Emissions of aromatic hydrocarbons, precursors to formation of dioxins and furans, are significantly reduced. Emission of formaldehyde from the engine, the most significant source of risk from the facility, was reduced by 98% to below 1 ppm. This reduction is achieved by the oxidation catalyst. This combination of a gas cleanup system, oxidation catalyst and SCR will not increase emissions of air toxics and reduces the major source of risk from continued operation of these engines. The CEQA document for proposed amended rule 1110.2 provides additional information of air toxic impacts for the proposed rule.

OCSD's final report recommended a less restrictive averaging time for biogas engines as a result of the pilot study data. Staff analyzed several possible averaging times to determine an acceptable time period that would address the exceedances without affecting the mass emissions. Using OCSD's 15-minute raw data from its pilot study, several averaging times were evaluated; the results listed in Table 5. Consistent with OCSD's analysis, only validated 15-minute block average data was used (not including exceedances due to start-up, atypical operating conditions, breakdowns, and system adjustments).

Table 5. OCSD Pilot Study NOx CEMS Data

Averaging Time (hours)	Number of 15-minute periods >11 ppmv
0.25	182
1	18
2	4
3	4
4	4
6	2
8	0
10	0
12	0
16	0
24	0

Staff found that an 8 hour block-averaging time would address OCSD's exceedances above 11 ppmv. As a result of this analysis, staff is proposing for engines with controls achieving superior performance in terms of reducing emissions, a 24~~12~~ hour averaging time to be able to comfortably address NOx exceedances without affecting the overall mass emissions. This longer averaging time will be extended to CO as well in the Staff proposal. With the results obtained, the OCSD project has demonstrated that this type of control technology can prove effective for meeting the proposed Rule 1110.2 limits.

A consideration that is always taken when applying SCR technology is the potential for ammonia slip when injecting urea into any exhaust gas stream. Ammonia is a toxic compound, and careful control must be taken in order to prevent excess amounts from escaping out of the stack. A limit of 10 ppm was assigned on the project's research permit and the maximum level emitted was 5 ppm during the pilot demonstration. An important factor when adjusting urea injection rates is ensuring that sufficient amounts of urea are injected in response to the engine's load demand and/or NOx level in real time or as close to real time as possible. This is to prevent too much ammonia from escaping out of the stack while simultaneously preventing too little urea from entering the exhaust stream that can result in an increase in NOx out of the stack.

An installation that also uses an oxidation catalyst/SCR technology, but applied to a landfill, is located at the Ox Mountain Landfill in northern California (Figure 2). Ameresco is the facility operator of the biogas engines at this location. One of its six GE-Jenbacher engines on-site was outfitted with both a catalytic oxidizer and SCR system in 2009 and has been operating since. Data that has been obtained from the BAAQMD has shown that the proposed Rule 1110.2 limits are achievable. CEMS data obtained from 2010 shows a consistent performance level that is consistent with OCSD's pilot study. In addition, monthly emission data shows that the proposed emissions limits are being achieved on an average mass per brake horsepower hour basis. The engines experienced some problems soon after startup, but the catalysts have performed effectively since 2009. The oxidation catalyst employs a guard bed upstream of the catalyst to aid in protection from harmful contaminants. The SCR catalyst has not been replaced since start-up, and has yielded efficient NOx removal for over 26,000 hours. The NOx excursions above 11 ppm throughout the operation of this installation have been attributed to operational problems with the engines, the SCR urea injection system, and monitoring problems. There are many moving parts in a urea injection system and in CEMS equipment, so problems were experienced with plugged nozzles, condensation in sampling lines, sample pump failures, and NOx cell failures that led to NOx events above 11 ppmv. From Ameresco's experience at Ox Mountain, the oxidation catalyst has experienced decreased performance over time, but not above our proposed compliance limit of 250 ppmv. Engine wear has been suspected as the cause from the catalyst manufacturer, but there has been no evidence of any siloxane breakthrough or siloxane buildup at the oxidation catalysts for any of the six units.

Several biogas engine installations in the San Joaquin Valley are achieving compliant emissions today, running on dairy digester gas. Two installations (one at a winery and another at a dairy) are meeting the 11 ppmv NOx limit, but these engines are rich burn engines, and operate with NSCR post combustion controls. The source test results for NOx corrected to 15% O_2 ranged from 1 to 10 ppmv for those engines. However, another installation for a lean burn engine at a dairy is achieving the proposed 11 ppmv NOx limit with SCR. The most recent source test resulted in a NOx concentration of 5.63 ppmv @15% O_2 (a 93% NOx reduction).

Figure 2. Ox Mountain's Landfill Gas to Energy Facility in Half Moon Bay, CA

NOXTECH

NOxTech is another post combustion control technology which provides a selective non-catalytic reduction, does not require gas cleanup, and is capable of achieving multi-pollutant control of NOx, VOC, and CO. Engine exhaust gases enter the unit where the temperature is raised by a heat exchanger. The gases then enter a reaction chamber where a small amount of the engine's fuel is added to raise the gas temperature to 1400-1500°F. At this temperature in the reaction chamber, NOx reduction can occur using urea injection, while CO and VOC are simultaneously incinerated. The system is designed to handle biogas that is of a lower BTU content than higher BTU natural gas. Natural gas has a BTU of 1,050 BTU per cubic foot, while biogas has a BTU range (depending of the methane content) of approximately 650 BTU per cubic foot.

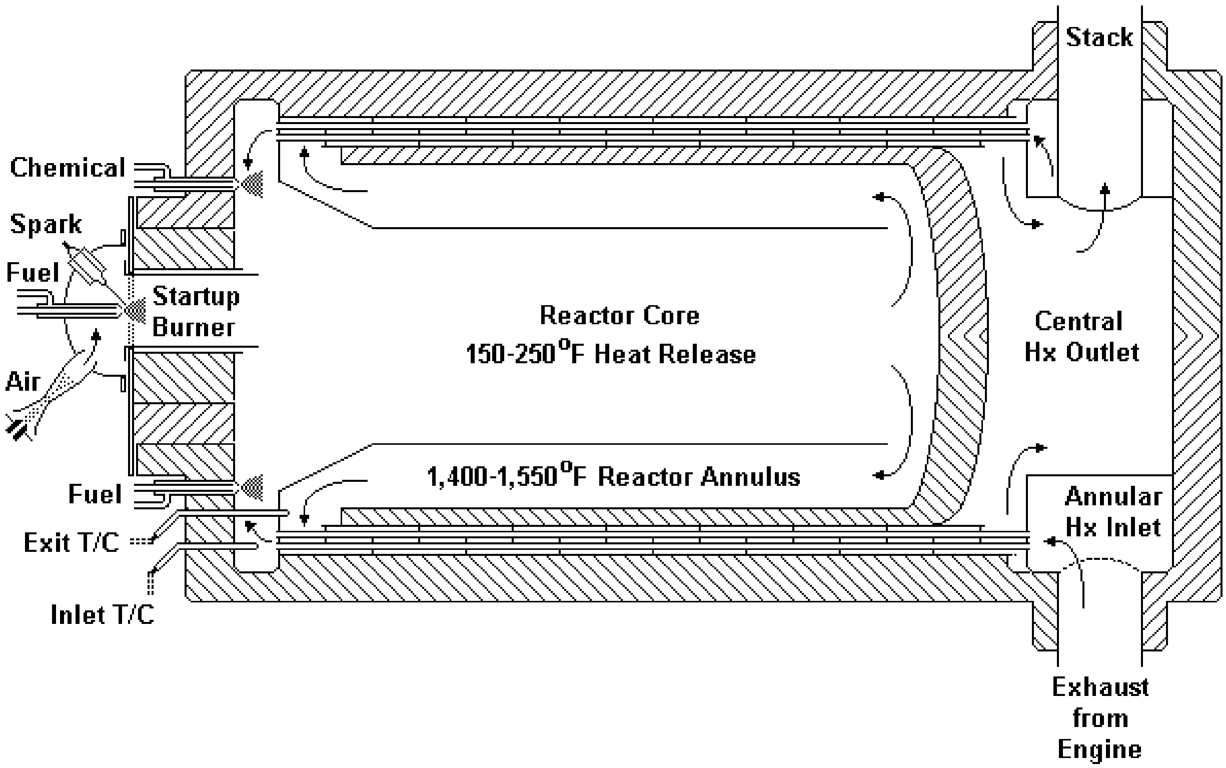


Figure 3. NOxTech System

As mentioned in the Interim Technology Assessment, a full-scale demonstration of this technology occurred at Woodville Landfill in Tulare starting in 2006, which achieved favorable results. The NOxTech unit was able to achieve NOx, CO, and VOC emissions below the proposed rule limits while running on landfill gas and in combination with a diesel engine to produce more exhaust flow. This project operated for four and a half years until the landfill was no longer able to provide sufficient gas to the engine. Two NOxTech units were operated by Southern California Edison (SCE) on diesel engines on Catalina Island from 1995 to 2001. Staff has again requested information from SCE regarding its experience and performance from this demonstration project. In May 2010, Eastern Municipal Water District (EMWD) installed a NOxTech unit at its Mills Pumping Station in Riverside. This site operates three natural gas fired internal combustion engines and the NOxTech unit is capable of handling the exhaust gas streams for multiple engines up to a maximum total rating of 1.5 MW (approximately 2000 bhp, depending on efficiency). While originally designed to treat exhaust gases from biogas engines, EMWD opted to test the NOxTech system with its natural gas-powered engines. The NOxTech system installed downstream of natural gas-powered engines at EMWD experienced some setbacks and was not able to achieve NOx levels that were in compliance with the proposed 11 ppmv rule limit in 2011 because the system was operating at higher than expected temperatures, resulting in higher than expected thermal NOx formation. The combustion of a higher BTU natural gas fuel also burns more quickly, elevating the exhaust temperatures. A variance was granted by the AQMD for the installation and additional testing of an Exhaust Gas Recirculation (EGR) system that is designed to lower the temperature enough to prevent excess NOx formation. This enhanced system commenced testing in April 2012 and has shown some promising results. The system is still being optimized to be able to consistently perform at the proposed emission levels. The installation of a new EGR fan this year is expected to handle the elevated exhaust temperatures in order to provide more recirculated exhaust gas to the unit and lower the NOx emissions further. A second NOxTech unit is set to be~~gin~~ installed to control the ~~construction at the~~ EMWD Temecula facility's digester gas-fired engines by the end of~~later~~ this year.

For engines larger than 1.5 MW, an additional unit is required to handle the flow while a third unit is required for engines larger than 3 MW. Unlike with EMWD, a landfill application would not require an EGR system because there typically is no natural gas backup fuel to run through the unit and because of the lower BTU content of the landfill gas.

A NOxTech system can be a less costly installation that a traditional catalytic oxidation/SCR installation due in large part to the anticipated decreased operations and maintenance (O&M) costs. Periodic sorbent and catalyst replacements are a significant portion of the O&M costs incurred with the operation of a catalytic oxidation/SCR system. While urea injection is still a required component of a NOxTech system, it eliminates the need for any gas cleanup sorbents and post combustion catalysts.

ALTERNATIVE TECHNOLOGIES

This section provides a brief description of~~n~~ alternative technologies that can be utilized to produce power from biogas with a much lower criteria pollutant emissions profile than that of biogas-fueled IC engines.

Fuel Cells

Fuel cells are an emerging technology capable of producing power with very low pollutant emissions without the utilization of combustion. In fact, fuel cells can produce electricity much more efficiently (between 45-50% efficiency) than combustion-based engines and turbines.

While there are a variety of fuel cell types available, fuel cells for biogas applicability use a molten carbonate cell to create an electrochemical reaction with the inlet biogas at the anode and oxygen from air at the cathode. Hydrogen is created in a reforming process at the anode, while carbonate ions are created at the cathode. The hydrogen gas reacts with the carbonate ions to produce water and electrons. These electrons flow through an external circuit that produces the electricity for the power plant.

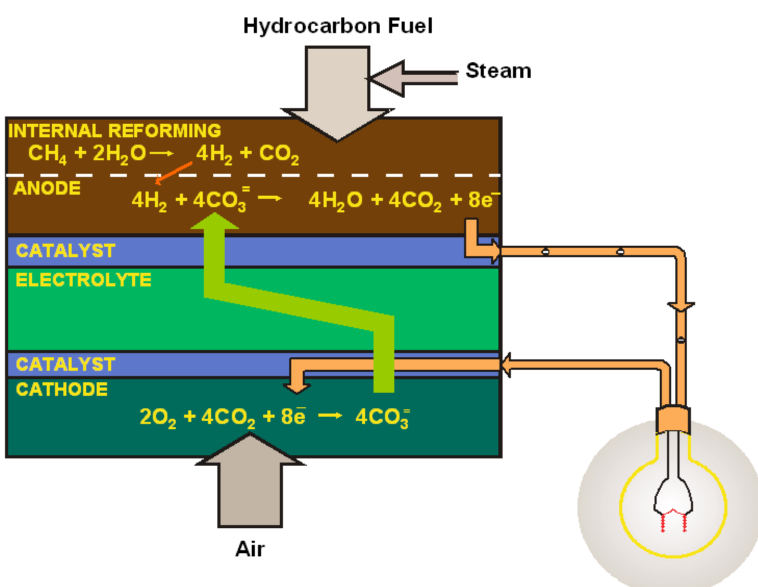


Figure 4. Fuel Cell Chemistry for Power Generation

These electrochemical reactions are produced in individual molten carbonate electrolyte stacks. The stacks are modular in design, so the total power production capacity of the generating plant can be tailored to accommodate several fuel cell stacks to meet the desired power output. The heat generated by the fuel cells can also be recovered and used to provide process heat. For instance, the recovered heat can be used to supply heat to a wastewater treatment plant's anaerobic digesters. The fuel cell stacks, however, are sensitive to impurities, so a gas cleanup system is critical to maintain the performance of the fuel cell stacks. Siloxanes, particularly, can foul a fuel cell.

There are many fuel cell installations that run on natural gas, but the activity of digester gas fuel cells in California is significant. There are five installations in the basin located at wastewater treatment plants that are designed to operate on biogas from anaerobic digesters. EMWD has installed a fuel cell power generating facility at the Moreno Valley Regional Water Reclamation Facility and at the Perris Valley facility, while the City of Rialto has also installed a digester gas fuel cell. The City of Riverside has installed a fuel cell system at its wastewater treatment plant and Inland Empire Utilities Agency (IEUA) has completed construction of a 2.8 MW fuel cell plant at its regional plant in Ontario that began~~will begin~~ operating in June 2012 on natural gas, while digester gas will be gradually introduced into the system. It is the largest fuel cell that will be operating in the state. The installations at EMWD Moreno Valley and the City of Riverside have encountered some issues with the early design fuel cells. Specifically, the stacks were not producing the electrical output they are rated for. Fuel Cell Energy (FCE), the equipment manufacturer, is currently in the process of negotiations with the facility operator, which would involve replacing the fuel cell stacks at Riverside. EMWD Moreno Valley has restacked the fuel cells and is currently operating. It was found that the cause for the decreased fuel cell stack life was from poisoning by sulfur compounds that the gas cleanup system was not removing sufficiently. FCE now offers to handle the procurement of the gas treatment skid at the time a fuel cell is purchased along with its servicing, as well as aiding in the selection of a third party gas treatment vendor if an operator desires.

Additionally, there are 2 installations in the San Joaquin Valley in Tulare and Turlock. The Turlock installation is currently down because of a lack of digester gas fuel. Two installations are in the Bay Area at Dublin San Ramon (operating) and in San Jose (in the commissioning phase). There is also an installation in Oxnard that is operating well and in San Diego, a group of units will be started up. Fuel~~s~~ cells installed at wastewater treatment plants can take advantage of SGIP (Self-Generation Incentive Program) funds to offset the capital costs of installation.

An installation under a research permit is also currently underway at OCSD. This unit operates primarily on anaerobic digester gas with the ability to also run on natural gas or a blend of both. It is an experimental installation because the fuel cell operates in conjunction with a hydrogen recovery unit that sends the recovered hydrogen gas to a nearby hydrogen fueling station for use by the public. This project is a collaboration of the United States Department of Energy (DOE), CARB, Air Products and Chemicals, and Fuel Cell Energy. It is expected to operate until 2014 and is intended to demonstrate an alternative energy source while reducing energy costs and reducing emissions. This fuel cell utilizes a gas cleanup system that removes sulfur compounds and, to date, has resulted in satisfactory performance of the fuel cell.

Flex Energy

Flex Energy is a system that combines microturbine technology with that of regenerative thermal oxidation to produce power with an ultra low emissions profile and without the necessity of biogas cleanup. The system is capable of taking low BTU content biogas that would be otherwise incombustible by any engine or turbine and diluting it before introducing it to a flameless thermal oxidizer that raises the temperature to destroy VOC and CO. The thermal oxidizer's temperature is also not raised so high as to facilitate the formation of thermal NOx. This process results in the consumption of methane gas without the pollutants from traditional combustion.

An open landfill will produce gas with a more or less constant amount of methane, roughly 50%. The other 50% is typically CO_2. However, once a landfill ceases to accept municipal solid waste, the amount of gas produced by the landfill will begin to decay gradually. A typical internal combustion engine that runs on landfill gas will struggle if the methane content of the biogas drops below 35-40%. Landfills that produce gas with a methane content lower than what an engine can use will typically send the gas to a flare for combustion. An advantage of the Flex Energy system is that it is capable of handling biogas with a methane content similar to what an engine consumes down to a level that is outside an engine's range of consumption. A Flex Energy system can consume landfill gas well after a landfill closes and well after an engine ceases operation due to the low methane content.

Another advantage with this type of system is that it does not require a fuel cleanup system for siloxanes and other impurities. Like the fuel cells, these systems can be modularly applied, based on the inlet characteristics of the biogas and desired power output.

Figure 5. Flex Energy FP250 Flex Powerstation

A pilot study of a Flex Energy installation was recently successfully completed at Lamb Canyon Landfill in Riverside County, CA. A Flex Energy installation is currently collecting data at a landfill in Fort Benning, GA, while approval has been granted for another installation at the Santiago Canyon Landfill in Orange County, set to begin operating later this year.

H_2 Assisted Lean Operation (HALO)

This emerging technology is based on injecting hydrogen gas into the inlet biogas stream before introduction into the engine's combustion chamber. Three to six percent hydrogen gas by mass in the fuel stream is sufficient to extend the lean limit combustion stability for the biogas fuel. Hydrogen's rapid combustion speed, wider combustion limit, and low ignition limit allows for a reduction in the exhaust emissions. There is no need for gas cleanup with the system and it takes up about a cubic meter of space. Some natural gas is required as feedstock for hydrogen production, but produces additional electrical output and heat that can benefit a biogas facility that utilizes waste heat. The addition of hydrogen reduces hydrocarbon and CO emissions, while the leaner burning fuel lowers the combustion temperature and, therefore, lowers NOx formation.

There is no need for gas cleanup or catalytic after-treatment with hydrogen injection and it has been tested by several engine manufacturers on natural gas engines. An added benefit is also an increase in the efficiency of an engine with hydrogen enrichment. A project with the City of San Bernardino Municipal Water Department is expected to commence at the latter part of 2012 on its two, 999 bhp, cogeneration engines.

Other Combustion Technologies

Traditional gas turbines, boilers and flares fall under this category. Several landfills in the basin currently employ the use of gas turbines for the combustion of the biogas and also require extensive gas cleanup to protect the turbine blades from siloxane buildup. For example, the Calabasas Landfill operated by Los Angeles County Sanitation District and the Brea-Olinda Landfill currently use turbine technology with gas cleanup for handling landfill produced biogas. The Chiquita Canyon Landfill installation, operated by Ameresco, uses a TSA gas cleanup system similar to the one at Ox Mountain and is currently in the optimization phase. Traditional boilers can also process biogas and currently are being used by both landfills and wastewater treatment plants across the basin. For example, if a facility that operates both engines and boilers elects to shut down its engines, the remaining biogas may be handled by its boilers and any excess can be routed to the facility flare, if necessary. Boilers are less sensitive to impurities, do not require extensive gas cleanup, and can provide waste heat. The last resort for any facility that handles biogas, but cannot combust it because of an insufficient quantity or due to equipment decommissioning, would be to flare. With flaring, a facility can achieve VOC destruction from combustion, while many newer BACT flares achieve low NOx emissions. However, there are some possible CO_2 emission impacts from a greenhouse gas perspective and these will be discussed in another section of this document. There are also systems available that recover the heat from a flare for process heat or even for electrical generation. ABUTEC has produced a heat recovery flare that captures the waste heat for process utilization and a unit by UTC Power uses an organic Rankine cycle to recover the heat from a flare and produce up to 200 kW of electrical power. Figure 6 shows a comparison between source test average emissions among different technologies. Boilers, gas turbines, and microturbines overall have lower emission profiles than IC engines.

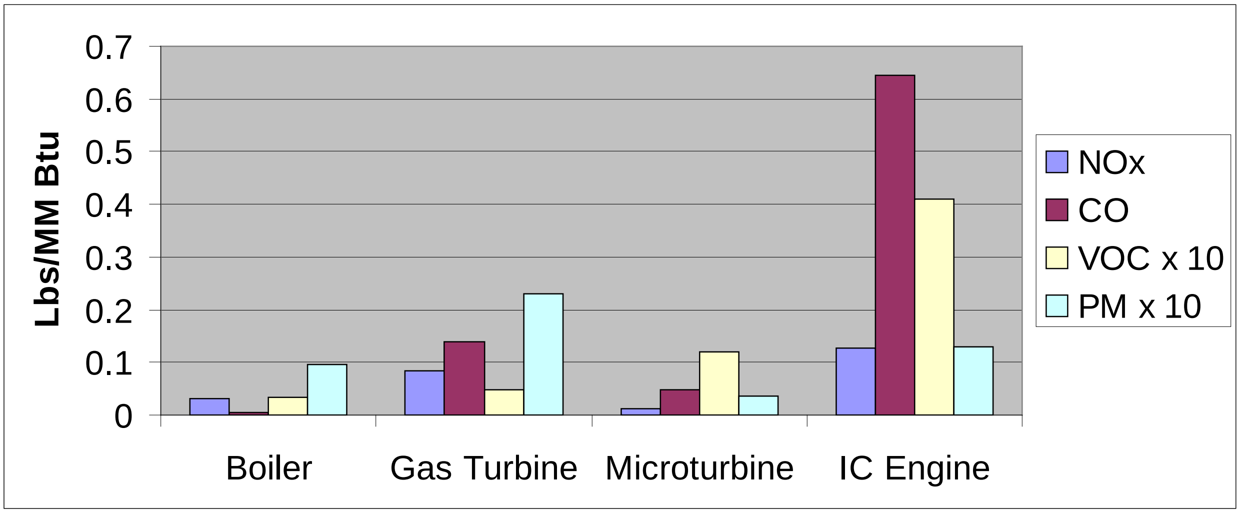


Figure 6. Emissions Comparison Among Different Biogas Electric Generation Technologies

COST AND COST EFFECTIVENESS

The cost and cost effectiveness analysis for this report relies on real data obtained from OCSD demonstration project. The pilot study demonstration project at OCSD is an example of an achieved in practice installation that has produced favorable results and that is cost effective. This installation used a digester gas cleanup system with a catalytic oxidizer and SCR for post-combustion emissions controls. In OCSD's case, additional structural work was required to support the placement of the catalytic oxidizer and SCR units. An overhead steel platform had to be constructed to support the equipment while allowing vehicle traffic to proceed underneath and to allow for urea deliveries.

The capital costs included the supporting steel necessary for the platform construction, while the annual operating costs included digester gas cleaning media replacement, oxidation catalyst and SCR catalyst replacement, and urea replacement. As a result of the gas cleanup system providing cleaner biogas to the engine, subsequent O&M costs to the engine itself were reduced as well as the frequency of maintenance operations.

The original vendor guarantee was three years for the catalysts, but near the end of the second year of operation (operating under a research permit), the CO emission levels began to rise. The emission levels got to just above 100 ppmv before the catalyst was removed from service and samples were sent for testing (average outlet CO ppm level was 7.5 ppmv during the pilot study). The results confirmed that there was some deactivation of the catalyst evidenced by the presence of a variety of contaminants suspected to originate from the operation of the engine. Although there was an elevation in the CO emissions, this cannot constitute a catalyst failure since the outlet CO emissions were still in compliance with the proposed CO limit of 250 ppm before removed from service. The oxidation catalysts at Ox Mountain have experienced something similar and yet have been achieving compliance with Staff's proposed CO limit for almost three years. Despite this, a catalyst replacement interval of two years, instead of three years, has been applied as part of the cost analysis described in further detail below.

Emissions and emission reductions are calculated for NOx, VOC, and CO. The current emissions are calculated from the current Rule 1110.2 rule limits and permit limits, while the future emissions are calculated from the proposed Rule 1110.2 limits. Permit limits were used for some engines because they were permitted at BACT or have more stringent permit limits than in the current rule. For calculating cost effectiveness, the AQMD uses the Discounted Cash Flow (DCF) model, which takes into consideration both capital cost plus annual operating and maintenance costs. This use of this model is consistent with previous rulemaking proposals and past control measures because it links the cost of the project with its environmental benefits. The equipment is given a twenty year life and a 4% interest rate. The calculated present worth value (PWV) is then divided by the summation of the emission reductions over the length of the project (20 years). The emission reductions for CO are discounted by one seventh because of its ozone-formation potential is approximately one seventh from that of NOx.

The 2008 Interim Technology Assessment provided preliminary cost information for a non-regenerative siloxane removal system with oxidation catalyst and SCR, based on OCSD's pilot study cost estimates as the project was beginning. Table 6 provides a comparison between the cost estimates from the Interim Report and those obtained from OCSD's Final Report on its pilot study. The emission reductions in the Interim Report did not include those from CO and assumed an annual operation of 8,000 hours. This explains the difference in the cost effectiveness between the Interim Report and OCSD's final report.

Table 6. Comparison of OCSD's Costs for Pilot Study Installation and Operation

	Interim Report	Final Report
Installed Equipment, $	1,265,000	1,989,529
Equipment minus Catalyst, $	*1,096,000*	*1,875,129*
Catalyst Cost, $	*169,000*	*114,400*
Project Management & Installation Supervision, $	285,000	298,429
Total Initial Investment, $	**1,550,000**	**2,287,958**
Sorbent Replacement, $/yr	62,000	40,000
Catalyst Replacement, $/yr (3 year replacement)	56,000	38,133
Reactant, $/yr	15,238	18,900
Reduced Power Production, $/yr	2,363	1,200
Equipment Maintenance, $/yr	-7,440	-30,147
Total Annual Cost, $	**128,161**	**58,950**
Present Value of 20-yr Cost, $	**3,360,916**	**3,089,089**
NOx Reductions	15.18	10.7
VOC Reductions	2.20	14.6
CO Reductions	0	64.9
Cost Effectiveness ($/ton NOx+VOC+CO/7)	**11,100**	**4,500***
$/kW-hr	**0.08**	**0.01**

*This figure is based on permit-specific limits that are lower than the current Rule 1110.2 limits and on 6,000 annual operating hours.

The actual capital costs were higher than was estimated in the Interim Report, but the operation and maintenance costs were actually lower due to the reduced engine maintenance and emission fee credits from the lower emissions. The calculated cost effectiveness of OCSD's 3471 bhp engine and based on the Final Report is $4,500 per ton of NOx, VOC, and CO/7. OCSD's permit limits for its demonstration project engine are 45ppmv NOx, 209 ppmv VOC, and 590 ppmv CO. Some facilities such as OCSD use the efficiency correction factor (ECF) to operate at a slightly higher NOx and/or VOC limit, for example.

The installation and operating costs for OCSD's system were scaled across a series of varying digester gas engine sizes representative of the current population. OCSD's cost effectiveness was calculated based on 6,000 annual operating hours for the pilot study. The cost effectiveness for this analysis is based on 8,000 operating hours. 8,000 hours was used as a typical usage level for the engines analyzed for the Interim Report. Emissions reductions are calculated from the current Rule 1110.2 rule and permit limits to the proposed Rule 1110.2 limits. Table 7 summarizes these results for digester gas at the base level. The base level assumes a catalyst replacement every two years and the sorbent costs from the pilot study. The cost effectiveness range for digester gas is between $1,700 and $3,500 per ton of NOx, VOC, and CO/7.

Table 7. Base Level Cost Effectiveness for Digester Gas Engines Based on OCSD's Actual Costs

BHP	4200	3471	1600	1000	500	250
Installed Equipment, $	**2,240,791**	**1,989,529**	**1,230,965**	**921,665**	**602,807**	**395,072**
Equipment minus Catalyst, $	2,102,364	1,875,129	1,178,231	888,707	586,328	386,832
Catalyst Cost, $	138,427	114,400	52,734	32,959	16,479	8,240
Project Management & Installation Supervision, $	361,107	298,429	137,565	85,978	42,989	21,494
Total Initial Investment, $	**2,601,898**	**2,287,958**	**1,368,529**	**1,007,643**	**645,796**	**416,566**
Sorbent Replacement, $/yr	48,401	40,000	18,438	11,524	5,762	2,881
Catalyst Replacement, $/yr (every 2 yr)	69,213	57,200	26,367	16,479	8,240	4,120
Reactant, $/yr	22,869	18,900	8,712	5,445	2,723	1,361
Reduced Power Production, $/yr	2,859	1,200	1,089	681	340	170
Equipment Maintenance, $/yr	-36,479	-30,147	-13,897	-8,685	-4,343	-2,171
Total Annual Cost, $	**106,865**	**87,153**	**40,710**	**25,444**	**12,722**	**6,361**
Present Value of 20-yr Cost, $	**4,054,188**	**3,472,367**	**1,921,783**	**1,353,427**	**818,688**	**503,012**
NOx Reduction, tpy	12.6	10.5	4.8	3	1.5	1
VOC Reduction, tpy	29	24	11.1	6.9	3.5	1.7
CO Reduction, tpy	538.9	445.4	205.3	128.3	64.2	32.1
CO Reduction/7, tpy	77.0	63.6	29.3	18.3	9.2	4.6
Cost Effectiveness, $ per ton of NOx+VOC+CO/7	**1700**	**1800**	**2100**	**2400**	**2900**	**3500**
$/kW-hr	**0.008**	**0.009**	**0.010**	**0.012**	**0.014**	**0.017**

OCSD's actual equipment costs (gas cleanup, oxidation catalyst, SCR, platform) and operating costs (with catalyst change outs every two years) were also applied to landfill gas engines to determine their cost effectiveness. The equipment costs were increased to account for the higher inlet gas volume per BTU supplied to the engine. The cost effectiveness range for landfill gas is between $2,300 and $2,900 per ton of NOx, VOC, and CO/7. The base level cost effectiveness for this analysis is based on 8,000 operating hours and is summarized in Table 8.

Table 8. Base Level Cost Effectiveness for Landfill Gas Engines Based on OCSD's Actual Costs

BHP	4200	3471	2700	2000	1500
Installed Equipment, $	**2,345,061**	**2,082,529**	**1,781,763**	**1,479,753**	**1,239,133**
Equipment minus Catalyst, $	*2,206,634*	*1,968,129*	*1,692,774*	*1,413,835*	*1,189,695*
Catalyst Cost, $	*138,427*	*114,400*	*88,989*	*65,918*	*49,438*
Project Management & Installation Supervision, $	*361,107*	*298,429*	*232,140*	*171,956*	*128,967*
Total Initial Investment, $	**2,706,168**	**2,380,958**	**2,013,903**	**1,651,708**	**1,368,100**
Sorbent Replacement, $/yr	48,401	40,000	31,115	23,048	17,286
Catalyst Replacement, $/yr (every 2 yr)	69,213	57,200	44,494	32,959	24,719
Reactant, $/yr	22,869	18,900	14,702	10,890	8,168
Reduced Power Production, $/yr	1,664	1,200	1,069	792	594
Equipment Maintenance, $/yr	-36,479	-30,147	-23,451	-17,371	-13,028
Total Annual Cost, $	**105,669**	**87,153**	**67,930**	**50,319**	**37,739**
Present Value of 20-yr Cost, $	**4,142,210**	**3,565,367**	**2,937,073**	**2,335,538**	**1,880,972**
NOx Reduction, tpy	**12.6**	**10.5**	**8.1**	**6**	**4.5**
VOC Reduction, tpy	**1.3**	**1.1**	**0.8**	**0.6**	**0.5**
CO Reduction, tpy	538.9	445.4	346.4	256.6	192.5
CO Reduction/7, tpy	77.0	63.6	49.5	36.7	27.5
Cost Effectiveness, $ per ton of NOx+VOC+CO/7	**2300**	**2400**	**2500**	**2700**	**2900**
$/kW-hr	**0.009**	**0.009**	**0.009**	**0.010**	**0.011**

*The equipment costs were increased by $93,000 to account for the siloxane cleanup system's processing of a greater gas volume per BTU supplied to the engine

Several stakeholders have expressed concern over the high cost of gas cleanup, primarily to address the removal of siloxanes from the biogas inlet stream. In addition, all facilities have varying levels of impurities in the biogas and some may have to install additional pretreatment for sulfur compounds if the levels are high. Redundant siloxane removal systems are a necessity and must be capable of handing the base siloxane load as well as intermittent spikes. To address these concerns in the cost analysis, Staff analyzed two other scenarios where additional gas treatment contingencies were added to the operational costs. These costs are based on vendor quotes for the full scale of flow rates of all the affected biogas facilities. The media costs were then normalized to obtain "per engine" costs, which were then bracketed to the appropriate engine brake horsepower sizes. The carbon media change-out frequency is dependent on the siloxane level; the higher the siloxane level, the more frequent the media change-out. The cost of the media is correlated to the media weight relative to the flow rate and vessel size. Staff has assumed a worst case where media change-outs will be required once per month.

On top of this, Staff also included a 20% contingency to the equipment costs to account for any additional gas cleanup required or to account for backpressure considerations in smaller engines or for additional compression and chilling equipment. Vendor supplied equipment costs are in line with the scaled costs from the base scenario for both gas cleanup and catalytic after-treatment. The operating costs are the major contributor to the overall cost of the gas cleanup system. The following two tables (Tables 9 and 10) represent the worst case costs with the additional gas cleanup and the additional 20% equipment cost contingency applied.

Table 9. Cost Effectiveness for Digester Gas Engines Based on OCSD's Actual Costs with Additional Contingencies

BHP	4200	3471	1600	1000	500	250
Installed Equipment, $	2,240,791	1,989,529	1,230,965	921,665	602,807	395,072
Equipment minus Catalyst, $	2,102,364	1,875,129	1,178,231	888,707	586,328	386,832
Added Cleanup w/20% contingency	420,473	375,026	235,646	177,741	117,266	77,366
Catalyst Cost, $	138,427	114,400	52,734	32,959	16,479	8,240
Installed Equipment w/20% contingency, $	**2,661,264**	**2,364,555**	**1,466,611**	**1,099,407**	**720,073**	**472,438**
Project Management & Installation Supervision, $	361,107	298,429	137,565	85,978	42,989	21,494
Total Initial Investment, $	**3,022,371**	**2,662,984**	**1,604,176**	**1,185,384**	**763,062**	**493,933**
Sorbent Replacement, $/yr	165,600	138,000	69,000	103,500	51,570	12,420
Catalyst Replacement, $/yr (every 2yr)	69,213	57,200	26,367	16,479	8,240	4,120
Reactant, $/yr	22,869	18,900	8,712	5,445	2,723	1,361
Reduced Power Production, $/yr	2,859	1,200	1,089	681	340	170
Equipment Maintenance, $/yr	-36,479	-30,147	-13,897	-8,685	-4,343	-2,171
Total Annual Cost, $	**224,064**	**185,153**	**91,272**	**117,420**	**58,530**	**15,900**
Present Value of 20-yr Cost, $	**6,067,395**	**5,179,213**	**2,844,560**	**2,781,121**	**1,558,484**	**710,013**
NOx Reduction, tpy	12.6	10.5	4.8	3	1.5	1
VOC Reduction, tpy	29	24	11.1	6.9	3.5	1.7
CO Reduction, tpy	538.9	445.4	205.3	128.3	64.2	32.1
CO Reduction/7, tpy	77.0	63.6	29.3	18.3	9.2	4.6
Cost Effectiveness, $ per ton of NOx+VOC+CO/7	**2600**	**2600**	**3100**	**4900**	**5500**	**4900**
$/kW-hr	**0.012**	**0.013**	**0.015**	**0.024**	**0.027**	**0.025**

Table 10. Cost Effectiveness for Landfill Gas Engines Based on OCSD's Actual Costs with Additional Contingencies

BHP	4200	3471	2700	2000	1500
Installed Equipment, $	2,345,061	2,082,529	1,781,763	1,479,753	1,239,133
Equipment minus Catalyst, $	2,206,634	1,968,129	1,692,774	1,413,835	1,189,695
Added Cleanup w/20% contingency	441,327	393,626	338,555	282,767	237,939
Catalyst Cost, $	138,427	114,400	88,989	65,918	49,438
Installed Equipment w/20% contingency, $	**2,786,388**	**2,476,155**	**2,120,318**	**1,762,520**	**1,477,072**
Project Management & Installation Supervision, $	361,107	298,429	232,140	171,956	128,967
Total Initial Investment, $	**3,147,495**	**2,774,584**	**2,352,458**	**1,934,475**	**1,606,039**
Sorbent Replacement, $/yr	276,000	276,000	138,000	207,000	103,500
Catalyst Replacement, $/yr (every 2yr)	69,213	57,200	44,494	32,959	24,719
Reactant, $/yr	22,869	18,900	14,702	10,890	8,168
Reduced Power Production, $/yr	1,664	1,200	1,069	792	594
Equipment Maintenance, $/yr	-36,479	-30,147	-23,451	-17,371	-13,028
Total Annual Cost, $	**333,268**	**323,153**	**174,815**	**234,270**	**123,953**
Present Value of 20-yr Cost, $	**7,676,607**	**7,166,233**	**4,728,196**	**5,118,211**	**3,290,558**
NOx Reduction, tpy	12.6	10.5	8.1	6	4.5
VOC Reduction, tpy	1.3	1.1	0.8	0.6	0.5
CO Reduction, tpy	538.9	445.4	346.4	256.6	192.5
CO Reduction/7, tpy	77.0	63.6	49.5	36.7	27.5
Cost Effectiveness, $ per ton of NOx+VOC+CO/7	**4200**	**4800**	**4000**	**5900**	**5100**
$/kW-hr	**0.016**	**0.018**	**0.015**	**0.022**	**0.019**

The worst case costs, along with the base case costs were plotted on the following two graphs for digester gas and landfill gas (Figure 7 and Figure 8). Since every facility is unique in the flow rate, engine size, and number of engines installed, the bracketed sorbent replacement costs are not necessarily linear. However, there is a sufficient correlation to apply a polynomial regression to each curve (with additional gas cleanup and with 20% additional contingency) and be able to represent them here. The worst case scenario cost effectiveness range for digester gas is from $2,600 to $5,500 per ton and from $4,200 to $5,900 per ton for landfills.

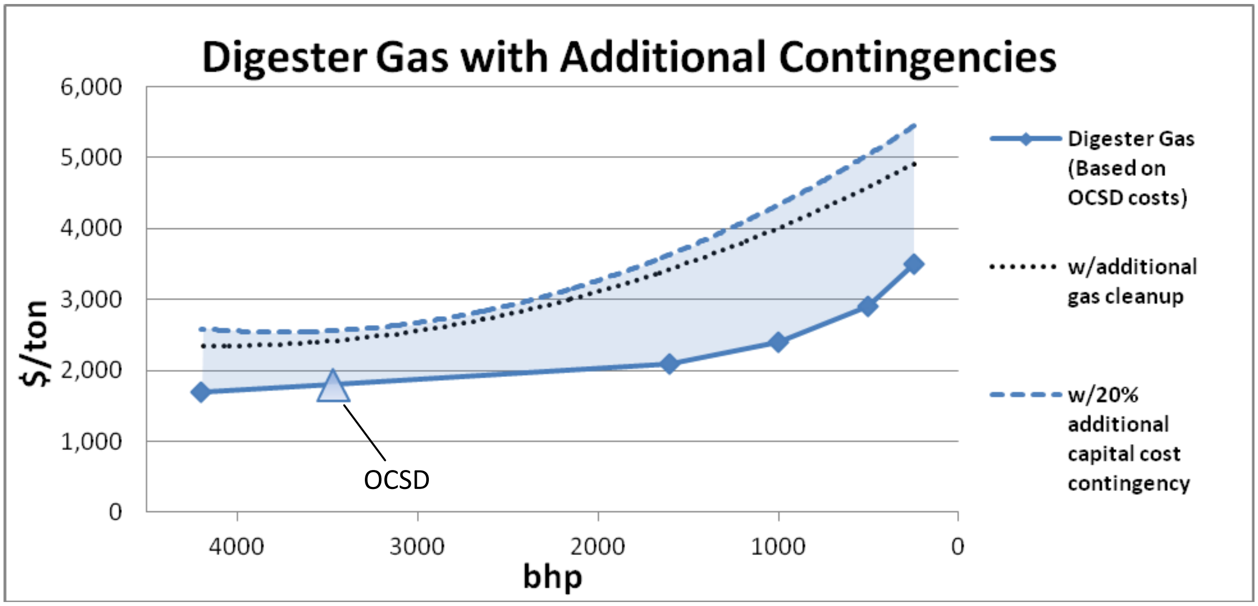


Figure 7. Cost Effectiveness for Digester Gas (Catalytic Aftertreatment)

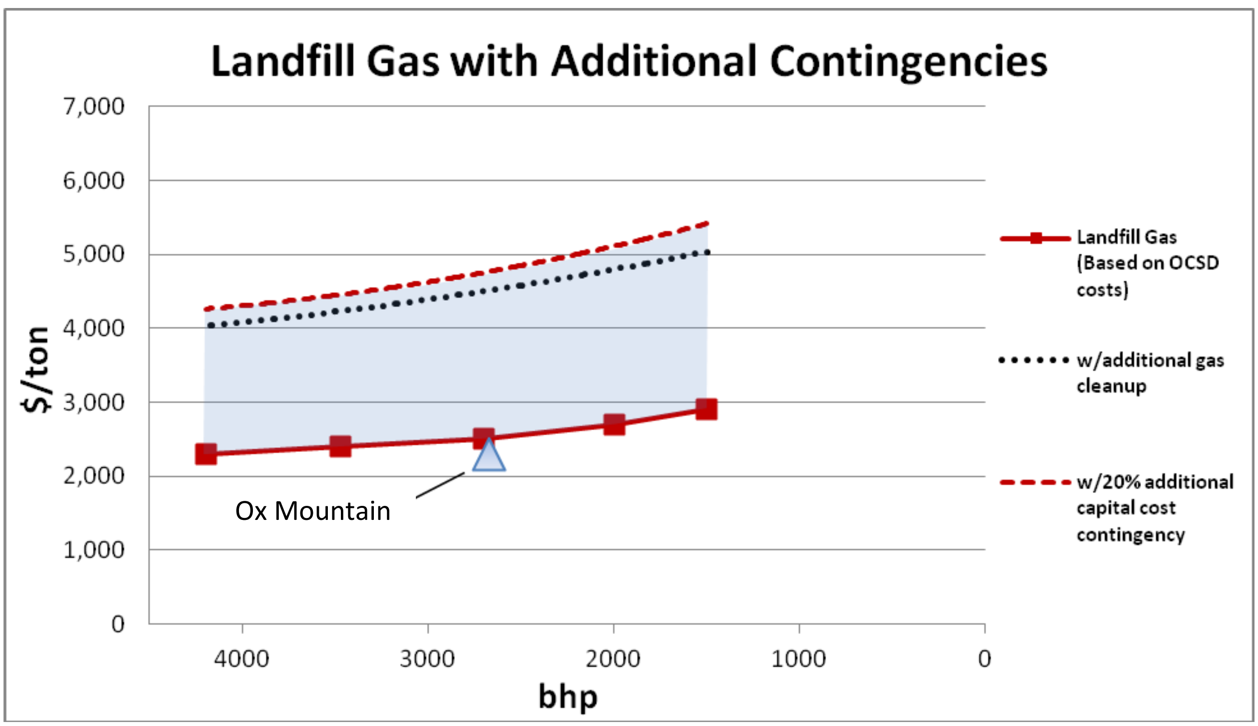


Figure 8. Cost Effectiveness for Landfill Gas (Catalytic Aftertreatment)

Cost data was also received from the Bay Area AQMD for the installation at Ox Mountain Landfill's 2,677 bhp engine with regenerative temperature swing adsorption (TSA) gas cleanup, oxidation catalyst, and SCR (Table 9). There are six total engines at that facility. Cost effectiveness was calculated from SCAQMD rule limits to the proposed rule limits, operating 8,000 hours per year. There may be an increased capital cost for a regenerative TSA system, but the total gas cleanup cost was divided by 6 to arrive at the per-engine estimate. The cost effectiveness for Ox Mountain is within the range of Staff's estimates for the proposed amendments (Figure 8). The annual costs presented here do not reflect any credit taken for reduced engine maintenance, so the actual operating costs may be lower than those in Table 11. From Ox Mountain's experience, the sorbent change-outs could be longer than once every twelve months.

Table 11. Cost Effectiveness of Landfill Installation with Regenerative Gas Cleanup, Oxidation Catalyst, and SCR

*Capital Costs**	
TSA System, $	271,544
TSA Installation, $	91,480
TSA Flare, $	25,105
TSA Flare Install, $	6,699
SCR System, $	46,218
SCR Install, $	28,960
Ox Cat System, $	38,218
Ox Cat Install, $	28,377
CEMS, $	170,165
CEMS Install, $	20,080
Design & Eng (3.4% of equip), $	18,742
Const & Comm (8% of equip), $	44,100
Total Installed Cost, $	**789,688**
Operating Costs	
TSA, $	14,000
Flare, $	2,917
CEMS, $	34,600
SCR, $	51,394
Ox Cat, $	12,514
Labor, $	10,000
Electricity, $	8,790
Total Annual Op Costs, $	**134,215**
PWV (20 yrs @4%), $	**2,613,673**
NOx Reduction, tpy	8.1
VOC Reduction, tpy	0.8
CO Reduction, tpy	343.5
CO Reduction/7, tpy	49.1
Cost Effectiveness, $ per ton of NOx+VOC+CO/7	**2,300**
$/kW-hr	**0.008**

*TSA system costs were divided by 6 to reflect a per-engine basis estimate

<u>NOxTech Cost Effectiveness</u>

Cost information was also obtained from NOxTech based on its installation at Eastern Municipal Water District's (EMWD) Mills Station. EMWD also submitted cost data reflecting the additional costs to install an EGR unit as it is currently undergoing further testing for its demonstration. For the cost effectiveness analysis, EMWD's additional costs amounted to a contingency for the installation costs of the NOxTech unit with EGR and its associated equipment. The addition of an EGR system is not anticipated to be required on landfill gas installations, so the contingency will be applied only to digester gas engines. The total amounts of contingency cost experienced by EMWD are not expected to be incurred by subsequent users. Table 11 shows the base level based on costs submitted by NOxTech for digester gas engines, while Table 12 shows the additional contingencies. Table 13 shows the base level only for landfill gas engines.

Table 11. Base Level Cost Effectiveness for Digester Gas Engines Based on NOxTech Costs

BHP	4200	3471	1600	1350	1000	500	250
Installed Equipment, $							
Equipment Cost, $	*960,000*	*800,000*	*400,000*	*400,000*	*400,000*	*400,000*	*400,000*
Installation Cost, $	*250,000*	*200,000*	*100,000*	*100,000*	*100,000*	*100,000*	*100,000*
Project Management & Installation Supervision, $	31,742	26,452	13,226	13,226	13,226	13,226	13,226
Total Initial Investment, $	**1,241,742**	**1,026,452**	**513,226**	**513,226**	**513,226**	**513,226**	**513,226**
Reactant, $/yr	37,952	31,365	14,458	12,199	9,036	4,518	2,259
Reduced Power Production, $/yr	68,365	56,499	26,044	21,975	16,277	8,139	4,069
Equipment Maintenance, $/yr	16,000	16,000	8,100	8,100	8,100	8,100	8,100
Total Annual Cost, $	**122,318**	**103,864**	**48,602**	**42,274**	**33,414**	**20,757**	**14,428**
Present Value of 20-yr Cost, $	**2,904,042**	**2,437,965**	**1,173,728**	**1,087,724**	**967,319**	**795,312**	**709,308**
NOx Reduction, tpy	12.6	10.5	4.8	4.1	3	1.5	1
VOC Reduction, tpy	29	24	11.1	9.3	6.9	3.5	1.7
CO Reduction, tpy	538.9	445.4	205.3	173.2	128.3	64.2	32.1
CO Reduction/7, tpy	77.0	63.6	29.3	24.7	18.3	9.2	4.6
Cost Effectiveness, $ per ton of NOx+VOC+CO/7	**1200**	**1200**	**1300**	**1400**	**1700**	**2800**	**4900**
$/kW-hr	**0.006**	**0.006**	**0.006**	**0.007**	**0.008**	**0.014**	**0.025**

Table 12. Cost Effectiveness for Digester Gas Engines Based on EMWD's Costs with Additional Contingencies

BHP	4200	3471	1600	1350	1000	500	250
Installed Equipment, $							
Equipment Cost, $	*960,000*	*800,000*	*400,000*	*400,000*	*400,000*	*400,000*	*400,000*
Installation Cost, $	*250,000*	*200,000*	*100,000*	*100,000*	*100,000*	*100,000*	*100,000*
Installation Cost Contingency, $	*300,000*	*300,000*	*300,000*	*300,000*	*300,000*	*300,000*	*300,000*
Project Management & Installation Supervision, $	31,742	26,452	13,226	13,226	13,226	13,226	13,226
Total Initial Investment, $	**1,541,742**	**1,326,452**	**813,226**	**813,226**	**813,226**	**813,226**	**813,226**
Reactant, $/yr	37,952	31,365	14,458	12,199	9,036	4,518	2,259
Reduced Power Production, $/yr	68,365	56,499	26,044	21,975	16,277	8,139	4,069
Equipment Maintenance, $/yr	16,000	16,000	8,100	8,100	8,100	8,100	8,100
Total Annual Cost, $	**122,318**	**103,864**	**48,602**	**42,274**	**33,414**	**20,757**	**14,428**
Present Value of 20-yr Cost, $	**3,204,042**	**2,737,965**	**1,473,728**	**1,387,724**	**1,267,319**	**1,095,312**	**1,009,308**
NOx Reduction, tpy	12.6	10.5	4.8	4.1	3	1.5	1
VOC Reduction, tpy	29	24	11.1	9.3	6.9	3.5	1.7
CO Reduction, tpy	538.9	445.4	205.3	173.2	128.3	64.2	32.1
CO Reduction/7, tpy	77.0	63.6	29.3	24.7	18.3	9.2	4.6
Cost Effectiveness, $ per ton of NOx+VOC+CO/7	**1400**	**1400**	**1600**	**1800**	**2200**	**3900**	**6900**
$/kW-hr	**0.007**	**0.007**	**0.008**	**0.009**	**0.011**	**0.019**	**0.035**

Table 13. Base Level Cost Effectiveness for Landfill Gas Engines Based on NOxTech Costs

BHP	4200	3471	2700	2000	1500	1350
Installed Equipment, $						
Equipment Cost, $	*960,000*	*800,000*	*800,000*	*400,000*	*400,000*	*400,000*
Installation Cost, $	*250,000*	*200,000*	*200,000*	*100,000*	*100,000*	*100,000*
Project Management & Installation Supervision, $	31,742	26,452	26,452	13,226	13,226	13,226
Total Initial Investment, $	**1,241,742**	**1,026,452**	**1,026,452**	**513,226**	**513,226**	**513,226**
Reactant, $/yr	37,952	31,365	24,398	18,073	13,554	12,199
Reduced Power Production, $/yr	53,041	43,834	34,098	25,258	18,943	17,049
Equipment Maintenance, $/yr	16,000	16,000	16,000	8,100	8,100	8,100
Total Annual Cost, $	**106,993**	**91,199**	**74,496**	**51,430**	**40,598**	**37,348**
Present Value of 20-yr Cost, $	**2,695,780**	**2,265,852**	**2,038,847**	**1,212,161**	**1,064,947**	**1,020,783**
NOx Reduction, tpy	12.6	10.5	8.1	6	4.5	4.1
VOC Reduction, tpy	1.3	1.1	0.8	0.6	0.5	0.4
CO Reduction, tpy	538.9	445.4	346.4	256.6	192.5	173.2
CO Reduction/7, tpy	77.0	63.6	49.5	36.7	27.5	24.7
Cost Effectiveness, $ per ton of NOx+VOC+CO/7	**1500**	**1500**	**1700**	**1400**	**1600**	**1700**
$/kW-hr	**0.006**	**0.006**	**0.007**	**0.005**	**0.006**	**0.007**

Figures 9 and 10 illustrate the cost effectiveness for NOxTech graphically. For digester gas, the shaded band reflects the possible contingency costs in relation to the base level costs. For landfills, the modular nature of the base level equipment costs from NOxTech result in a slightly less than linear representation. However, there is sufficient correlation to apply a regression that results in the curve illustrated in Figure 10.

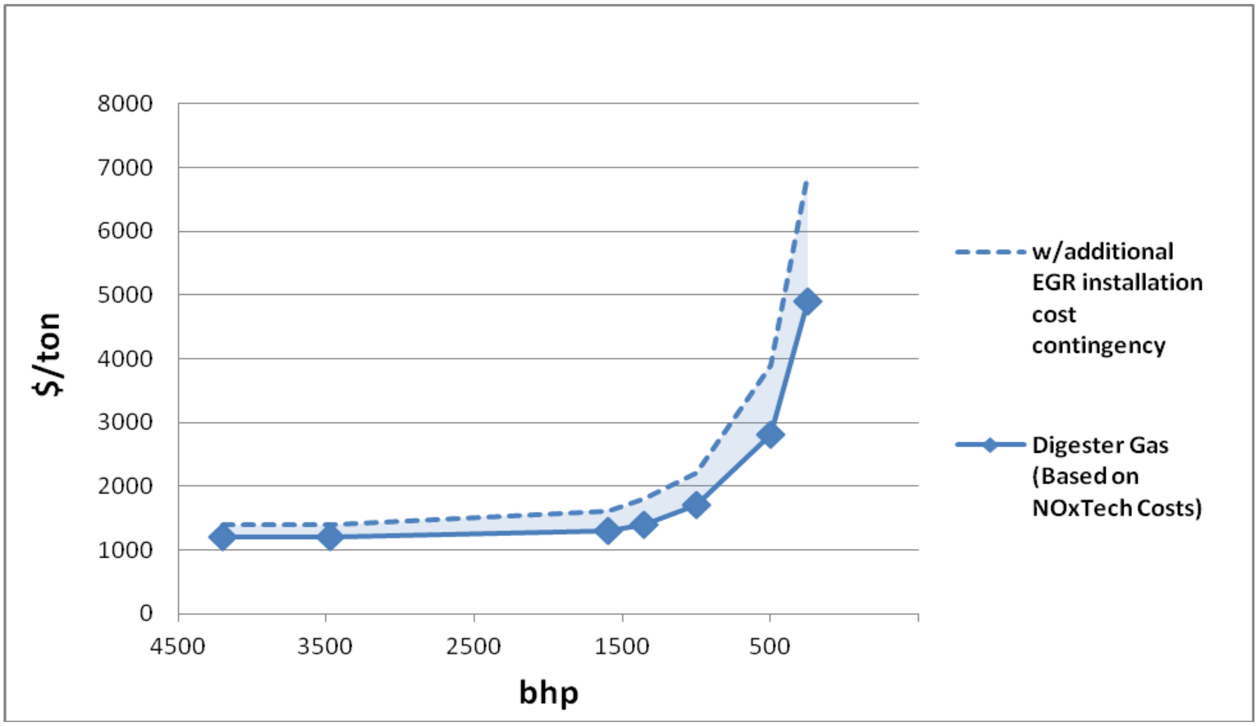


Figure 9. Cost Effectiveness for Digester Gas Based on NOxTech Costs with Additional Contingencies

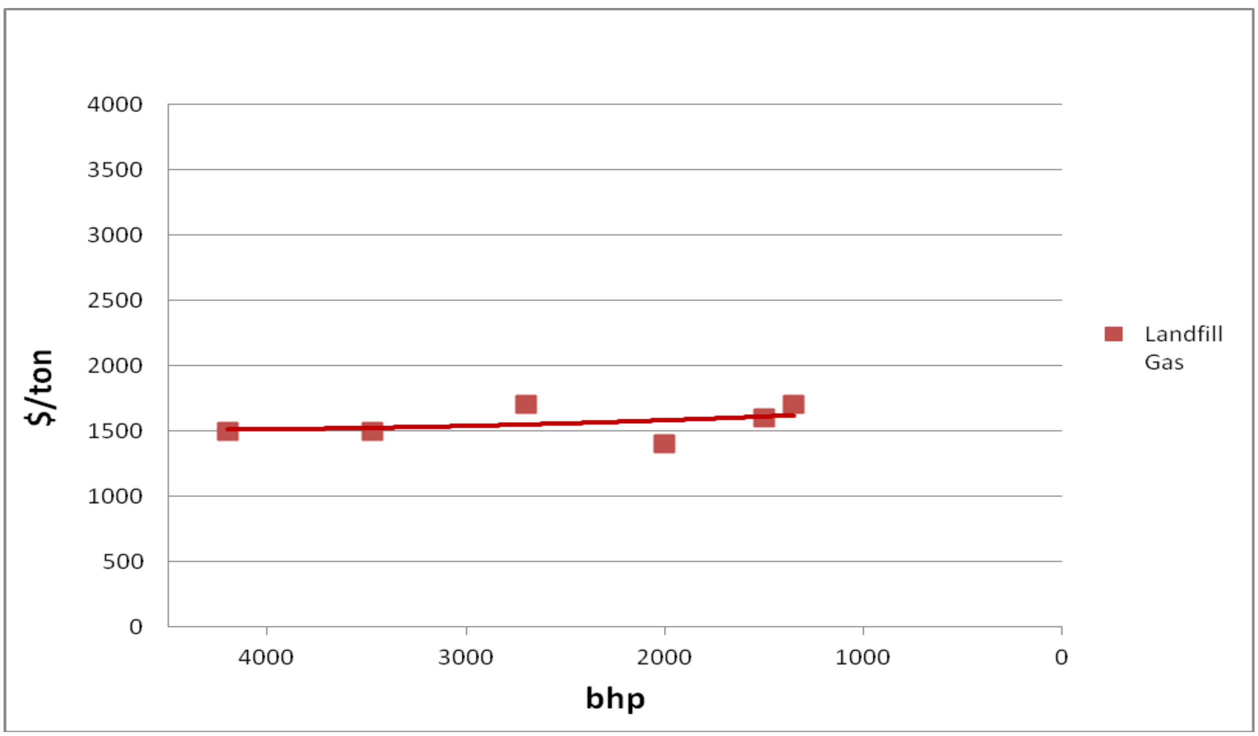


Figure 10. Cost Effectiveness for Landfill Gas Based on NOxTech Costs

The cost effectiveness estimates presented here are within the range of cost effectiveness estimates presented to the Governing Board for past rulemakings. Digester gas and landfill gas engines of all sizes are shown to be cost-effective for all scenarios. The dollars per kilowatt-hour estimates (which assume a 97% generator efficiency) also show that the addition of emission controls is cheaper than the cost of electricity from the grid which runs about 8 to 10 cents per kilowatt-hour.

GLOBAL WARMING IMPACTS

The Adopting Board Resolution for the February 1, 2008 amendment of Rule 1110.2 directed AQMD staff to prepare a Technology Assessment including a summary of potential trade-offs between greenhouse gas (GHG) and criteria pollutant emissions due to the adoption of the proposed biogas emission limits (NOx limit of 11 ppm (referenced to 15% O_2), VOC limit of 30 ppm and CO limit of 250 ppm). Operation of the IC engines using biogas to produce electrical power generates the three criteria pollutants NOx, VOC and CO. If the operators of those engines elect to cease power generation then the biogas must be flared or redirected to another usage onsite including fueling boilers. The choice to generate power or not leads to a trade-off: upgrade the power generation emissions controls to obtain a cleaner emissions profile or potentially shutdown the internal power generation and flare but in doing so release more greenhouse gases. The following discussion provides a comparison of the impacts the two options present: criteria pollutant emissions and greenhouse gas emissions from operation of the IC engines vs. flaring.

Criteria Pollutant Impact

Figures 11 through 13 compare emissions of criteria pollutants from existing engines, an engine meeting the proposed limits and biogas flares at facilities affected by the proposed biogas emission limits. The range of flare emissions shown in the following figures represents the variety of permit limits and operating conditions for flares at affected facilities. The permit emissions limits vary because the age of flares at these facilities ranges from less than 10 years to 40 years old. The emissions for each technology include the direct emissions from fuel combustion (natural gas). The flare emissions also include the criteria emissions from local utility power plants when biogas is directed to flares instead of being used to generate electricity using IC engines.

The NOx, VOC and CO emissions comparisons depicted in Figures 11 through 13 are expressed as a percent compared to the proposed engine emission limits – a ratio of the current and proposed emission limits in ppm or pounds of emissions per Btu of fuel consumed. In addition, Figures 11 and 12 show the range of the current NOx and VOC emission limits for large and small engines. Also included in the three figures are the estimates of flare emissions and the emissions from a large power plant. These emissions are included because when an engine is shut down, the replacement electricity is assumed to be generated by a local utility boiler or combined cycle turbine.

The comparison of criteria pollutant emissions from engines and flares uses the ratio of the emission limit for the specific technology to the emission factor for an engine meeting the proposed biogas emission limits (NOx limit of 11 ppm (referenced to 15% O_2), VOC limit of 30 ppm and CO limit of 250 ppm). This ratio is then converted to percent with the proposed engine limit set at 100%. This ratio can be generated by converting all emission limits to parts per million at 15% O_2 (the reference level for the Rule 1110.2 emission limits) or by converting all emission limits to pounds per million Btu.

The emission comparisons assume that the biogas is diverted to flares from engines and there is an equivalent amount of electricity produced by local power plants meeting current BACT. Compared to flares, power plant criteria pollutant emissions are smaller because limits are very low and base load power plants use one-half of the fuel of engines to produce the same amount of electricity. These emissions are included in Figures 11 to 13 as part of the flare emissions. While there are other sources of electricity outside the AQMD, the amount of electricity produced by biogas engines is small in comparison and local base load power plants have enough capacity to replace these sources at a cost-effective price.

As presented in the Figures 11 through 13, the option to flare emissions would generate less criteria pollutant emissions than are currently produced under the existing emissions limits, regardless of flare configuration. Operating the IC engines at the proposed limits would be cleaner for NOx and VOC than venting emissions to the Pre-1998 flares (which include the required base load emissions). In each case, flaring using a BACT flare, including the base load emissions would generate fewer emissions than for IC engines operating within the proposed new emissions limits. However, the option to flare raises illuminates the counterpoint argument: Does flaring result in a greater GHG emissions impact than generating internal power?

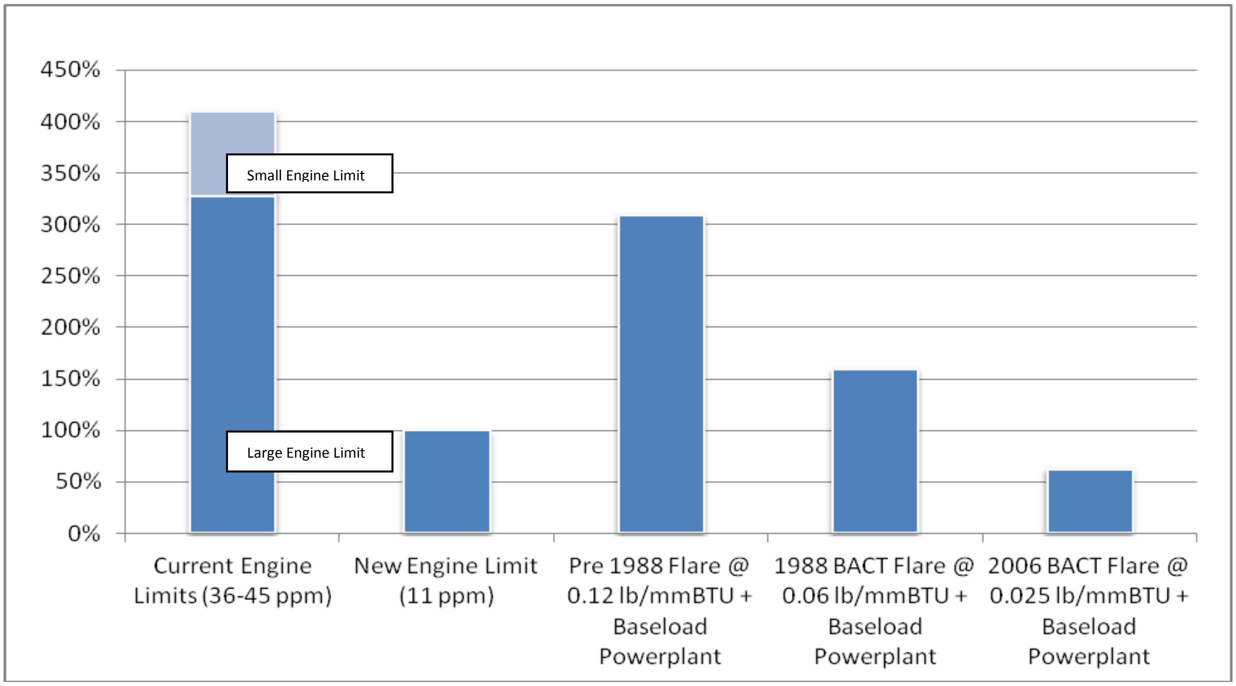


Figure 11

Biogas Flare and Engine NOx Emissions Compared to an 11 PPM Emissions Limit

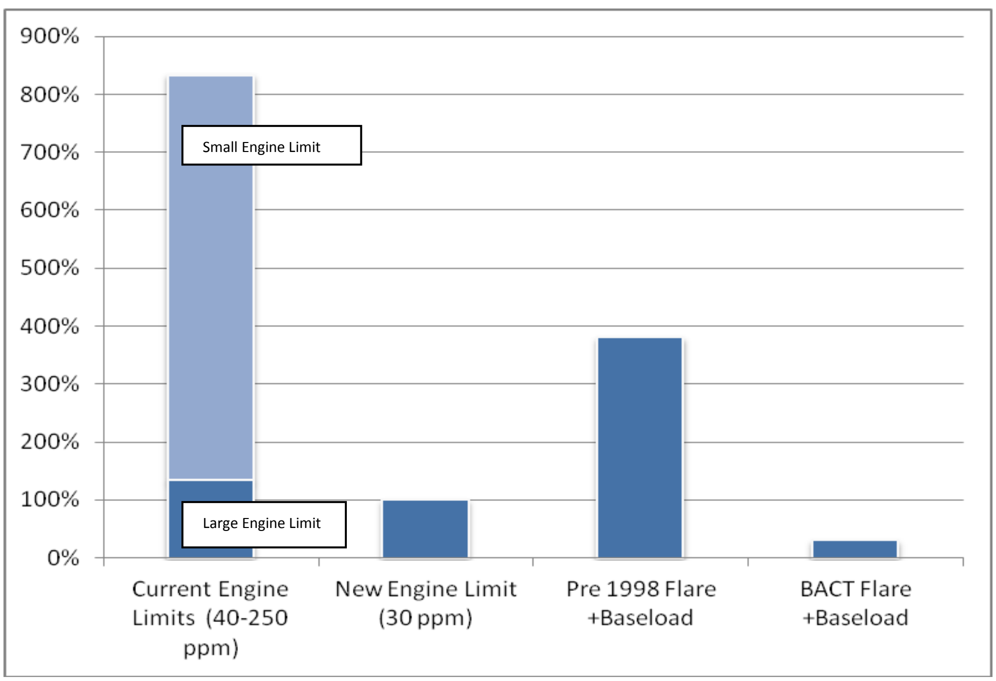


Figure 12

Biogas Flare and Engine VOC Emissions Compared to a 30 PPM Emissions Limit

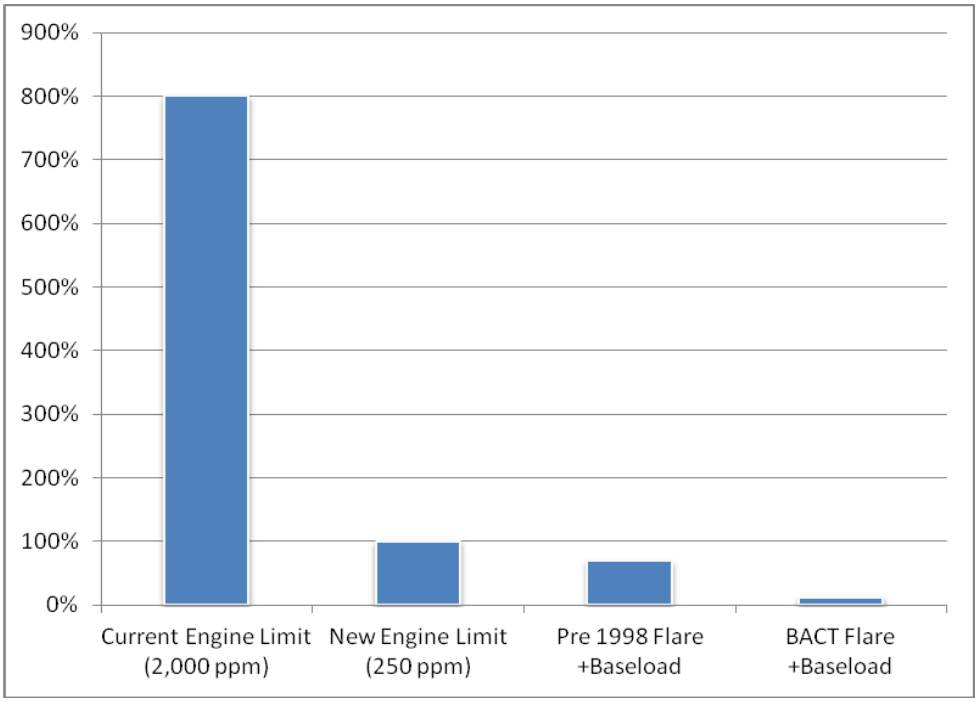


Figure 13

Biogas Flare and Engine CO Emissions Compared to a 250 PPM Emissions Limit

Greenhouse Gas Impacts

Figure 14 provides a comparison of greenhouse gas emissions impact from engines, flares and base load power generation. The figure includes emissions from engines using different amounts of supplemental fuel (natural gas), power plants and newer versus older flare technologies. The differences in GHG emissions are expressed as percent compared to biogas engine emissions. The GHG emission comparison in Figure 14 is based on carbon dioxide equivalents (CO_2e). Emissions of gases that contribute to global warming are represented as CO_2 equivalents by taking into account their warming potential in the atmosphere relative to CO_2. For example, methane (CH_4) is assigned a warming potential of 21 times CO_2 (over a 100 year timeframe).

More specifically, the comparison of GHG emissions is also a ratio of each technologies emissions (expressed as carbon dioxide equivalents – CO_2e) to the CO_2e associated with an IC engine using 15% supplemental natural gas. This ratio is developed on a mass basis. In the case of an IC engine and pre-2006 flare, it is assumed that for every 100 methane molecules provided as fuel to the engine, 99 are combusted to CO_2 and one is emitted in the exhaust. The global warming potential of this one methane molecule is equivalent to 21 CO_2 molecules. In addition, 15% of the fuel methane for the base engine and pre-2006 flare scenarios comes from natural gas. The 2010 U.S. EPA method for estimating the CO_2e GHG emissions related from natural gas production and transport to an average of about 20% of the fuel Btu delivered to an operation. In 2011, EPA revised its estimate upwards to average of about 35% of the fuel Btu delivered. Using the 2011 U.S. EPA percentage translates to an additional CO_2e of 6 more molecules of CO_2 due to production and transport of that natural gas. The summation of these emissions in terms of CO_2 equivalence results in an impact of 126 CO_2 molecules for every 100 molecules of methane provided to the engine.

The same methodology is used to generate the CO_2e emissions from an engine using 50% supplemental natural gas with the same Btu content, a flare meeting current BACT limits and a base load power plant generating the same amount of electricity as the IC engine (using ½ the Btu of an engine). A flare meeting 2006 BACT has more complete combustion and emits half of the methane than older flares emit and does not require supplemental natural gas. These “emissions” are then used to generate a ratio with the base engine represented as 100%. In this analysis, the electricity is produced by local power plants in order to determine the worst case emissions if engines are replaced with flares.

As depicted in Figure 14, operation of the IC engine using a 15 percent natural gas and 85 percent biogas is equivalent to 126 CO_2 molecules or a factor of 1.0 on the chart. An engine burning 50 percent natural gas has a higher ratio because of the additional production and transport contribution to the total CO_2e. Using a Pre 2006 (non-BACT) flare with the 15 percent natural gas contribution has an equivalent CO_2e signature as the biogas engine (1.0). The BACT flare and base load power generation (with the production and transport contribution to the total CO_2e) exhibit lower GHG impacts compared to the biogas engine or the Pre 2006 flare. However, if a facility elects to flare the gas with a Pre 2006 flare but acquires power from the grid, the factor approaches 1.8 or 80 percent more GHG emissions than continued operation of the IC engine. Even if a facility uses a BACT flare but needs supplemental power from the grid, the factor rises to approximately 1.5 or 50 percent GHG emissions above the continued operation of the IC engine.

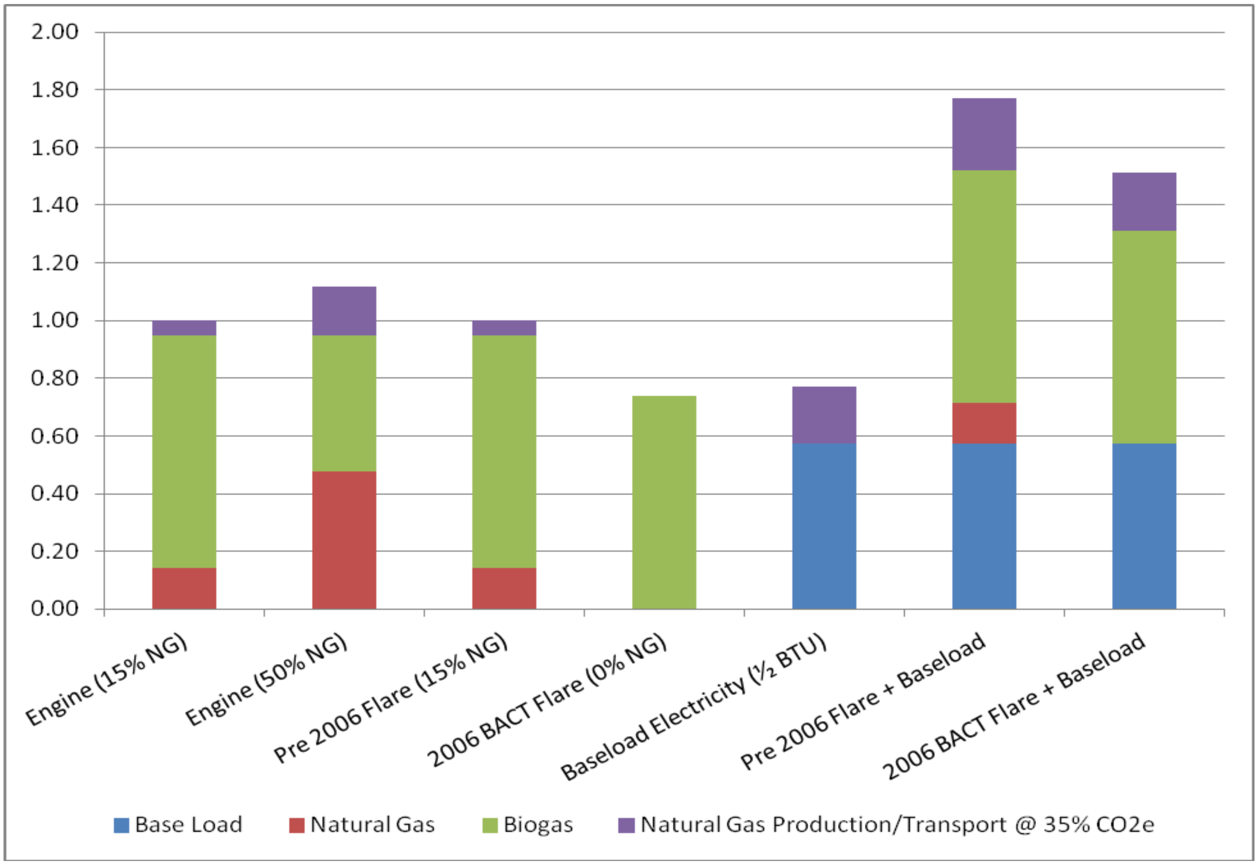


Figure 14

Comparison of CO_2 Equivalent Greenhouse Emissions from Flares and Base Load Electricity and IC Engines

<u>GHG Impact Summary</u>

The above analysis provides background assessments of the trade-off between achieving lower criteria pollutant emissions levels from complying with the proposed new standards and the possible GHG emissions penalty which may be incurred if a facility flares but is required to purchase power from the grid. Compared to current biogas engines, flares typically have lower criteria pollutant emissions profiles but have higher emissions of greenhouse gases because electricity must be generated by other sources if the biogas is not used in an engine generating electricity (Table 14).

Table 14. Comparison of Criteria Pollutant and GHG Impacts from ICE Operating and from Flaring

Pollutant	Magnitude of Flaring w/BACT Flare + Baseload Compared to ICEs
NOx	5 to 7x Less
CO	67x Less
VOC	4 to 27~~3~~x Less
GHG (CO_2e)	1.4x More

Flares meeting current BACT also have a significantly lower greenhouse gas impact compared to older flares. However, new BACT flares still result in about 50% more greenhouse gas emissions than current engines (on a CO_2e basis).

In general, criteria pollutant impacts have an immediate impact on public health and as such are typically given greatest weight. GHG gas goals set by AB32 and companion legislation target the long term control strategy to address global warming. Both issues have merit and deserve attention. One additional element that needs to be noted is energy conservation and the potential wasting of an available energy source (biogas) which is neither drilled nor mined.

CONCLUSION

The technology demonstration projects have shown that technology is available that can achieve significant reductions in NOx, VOC, and CO. Since the 2008 amendment of Rule 1110.2, oxidation catalyst and SCR technology has been effective in reducing pollutant emissions cost effectively for natural gas engines. At the time of the Interim Technology Assessment of 2010, this technology was in the early stages of being explored for the control of biogas engines as well. Since then, the demonstration project at OCSD was successfully completed for the control of biogas emissions from a digester gas facility. In addition, a sufficient amount of data over almost three years was obtained from Ox Mountain Landfill, demonstrating that the control of emissions from a landfill gas-fired engine is achievable on a consistent basis. The utilization of biogas cleanup with siloxane removal has proven essential for the protection of engine components and catalysts. Biogas cleanup systems are currently in use for the protection of engines as well as microturbines and turbines in the District today. These same systems can also clean the biogas effectively to protect the post-combustion catalytic controls as well.

In addition to catalyst technology, other technologies have emerged as viable alternatives such as the NOxTech system and Hydrogen Injection. Furthermore, technologies such as fuel cells and Flex Energy are viable alternatives for the replacement of IC Engine generated power altogether. The proposed compliance schedule is reasonable, and will allow facilities the needed time to procure, design, and install these systems. Additionally, the compliance schedule will allow enough time for other technologies to be demonstrated and will give facilities more options for compliance.

Alternatives also exist for those facilities, especially landfills, that have closed and whose biogas supply is decreasing below the usable level for IC Engines. In this case, the other alternatives that may be used are boilers, microturbines, or Flex Energy. It is ultimately an operator's decision to flare the biogas, as this also remains as an alternative. However, flaring is still viewed as undesirable due to the pollutant impacts and trade-offs. Cost effective technologies exist that can preclude flaring and still maintain a facility's power-generating capacity with the remaining amount of landfill gas.

The cost effectiveness analysis based on actual data for a digester gas facility shows that the technology is scalable and cost effective for digester gas engines of all sizes. From a dollars per kilowatt standpoint, the analysis shows that the cost of power production will not exceed the cost of purchasing the same power from the grid.

The proposed limits of Rule 1110.2 are feasible and cost effective. Technologies exist today that can achieve these emission limits within the compliance schedule in the Staff proposal. Given the aforementioned cost effective controls and reasonable compliance schedule, increased flaring is not anticipated to occur. On this basis, Staff recommends to move forward with Proposed Amended Rule 1110.2 while maintaining a commitment to continue working with the regulated community in monitoring the performance of on-going demonstration projects to assure that the compliance schedule is reasonable.

ATTACHMENT A

COST EFFECTIVENESS CALCULATIONS FOR RULE 1110.2 REQUIREMENTS FOR BIOGAS ENGINES

Gas Cleanup System + Oxidation Catalyst + SCR (20-year Equipment Life) – Cost basis is OCSD pilot study demonstration

	Digester	Digester	Digester	Digester	Digester	Digester	Landfill	Landfill	Landfill	Landfill	Landfill
BHP	4200	3471	1600	1000	500	250	4200	3471	2700	2000	1500
Installed Equipment, $ (Note 1)	2,240,791	1,989,529	1,230,965	921,665	602,807	395,072	2,345,061	2,082,529	1,781,763	1,479,753	1,239,133
Equipment minus Catalyst, $	2,102,364	1,875,129	1,178,231	888,707	586,328	386,832	2,206,634	1,968,129	1,692,774	1,413,835	1,189,695
Added Cleanup w/20% contingency (Note 2)	420,473	375,026	235,646	177,741	117,266	77,366	441,327	393,626	338,555	282,767	237,939
Catalyst Cost, $ (Note 3)	138,427	114,400	52,734	32,959	16,479	8,240	138,427	114,400	88,989	65,918	49,438
Installed Equipment w/20% contingency, $	**2,661,264**	**2,364,555**	**1,466,611**	**1,099,407**	**720,073**	**472,438**	**2,786,388**	**2,476,155**	**2,120,318**	**1,762,520**	**1,477,072**
Project Management & Installation Supervision, $ (Note 4)	361,107	298,429	137,565	85,978	42,989	21,494	361,107	298,429	232,140	171,956	128,967
Total Initial Investment, $	**3,022,371**	**2,662,984**	**1,604,176**	**1,185,384**	**763,062**	**493,933**	**3,147,495**	**2,774,584**	**2,352,458**	**1,934,475**	**1,606,039**
Sorbent Replacement, $/yr (Note 5)	165,600	138,000	69,000	103,500	51,570	12,420	276,000	276,000	138,000	207,000	103,500
Catalyst Replacement, $/yr (every 2yr, Note 6)	69,213	57,200	26,367	16,479	8,240	4,120	69,213	57,200	44,494	32,959	24,719
Reactant, $/yr (Note 7)	22,869	18,900	8,712	5,445	2,723	1,361	22,869	18,900	14,702	10,890	8,168
Reduced Power Production, $/yr (Note 8)	2,859	1,200	1,089	681	340	170	1,664	1,200	1,069	792	594
Equipment Maintenance, $/yr (Note 9)	-36,479	-30,147	-13,897	-8,685	-4,343	-2,171	-36,479	-30,147	-23,451	-17,371	-13,028
Total Annual Cost, $	**224,064**	**185,153**	**91,272**	**117,420**	**58,530**	**15,900**	**333,268**	**323,153**	**174,815**	**234,270**	**123,953**
Present Value of 20-yr Cost, $ (Note 10)	**6,067,395**	**5,179,213**	**2,844,560**	**2,781,121**	**1,558,484**	**710,013**	**7,676,607**	**7,166,233**	**4,728,196**	**5,118,211**	**3,290,558**
NOx Reduction, tpy (Note 11)	12.6	10.5	4.8	3	1.5	1	12.6	10.5	8.1	6	4.5
VOC Reduction, tpy (Note 11)	29	24	11.1	6.9	3.5	1.7	1.3	1.1	0.8	0.6	0.5
CO Reduction, tpy (Note 11)	538.9	445.4	205.3	128.3	64.2	32.1	538.9	445.4	346.4	256.6	192.5
CO Reduction/7, tpy (Note 12)	77.0	63.6	29.3	18.3	9.2	4.6	77.0	63.6	49.5	36.7	27.5
Cost Effectiveness, $ per ton of NOx+VOC+CO/7	**2600**	**2600**	**3100**	**4900**	**5500**	**4900**	**4200**	**4800**	**4000**	**5900**	**5100**
$/kW-hr	**0.012**	**0.013**	**0.015**	**0.024**	**0.027**	**0.025**	**0.016**	**0.018**	**0.015**	**0.022**	**0.019**

Notes for Gas Cleanup + Oxidation Catalyst + SCR:

1	From the OCSD Final Report for a 3,471 bhp engine, the construction subtotal for equipment and labor with contractor contingencies included is $1,989,529.
	The non-catalyst installed cost is assumed to vary with bhp$^{0.6}$ based on general chemical engineering cost estimating practice for tanks and reactors.
	For landfills, the installed cost of the siloxane removal system is higher because of the higher gas volume per BTU supplied to the engine. Additional cost for gas cleanup on a 3,471 bhp engine is $93,000.
2	A 20% contingency to account for possible additional gas cleanup equipment is added to the equipment costs minus catalyst
3	For the OCSD catalysts, there were 16 catalytic oxidizer blocks at $3,450 per block and thirty-two SCR catalyst blocks at $1,850 per block.
	Catalyst cost is assumed to vary directly with bhp.
4	Cost for project management and installation supervision for OCSD was calculated as a 15% contingency of the installed equipment costs, not including the 20% contingency accounting for possible additional gas cleanup equipment.
5	Vender quotes were obtained for non-regenerative activated carbon vessels/media and were sized and bracketed according to flow rate. Change-out frequency is once every month. The total cost for the media replacement was divided by the number of engines per facility to arrive at a per engine cost. The highest cost at each bracketed engine size was used.
	OCSD's media replacement cost from the pilot study was $40,000 for one year on a 3,471 engine.
6	OCSD experienced a partial deactivation of its oxidation catalyst after two years of operation. Staff has accounted for this by using the annual cost for a biannual catalyst replacement.
7	Cost of urea is based on OCSD's annual cost. Reactant cost is assumed to vary directly with horsepower.
8	Pressure drops across the siloxane removal and SCR systems are assumed to be 3" H_2O each. Calculated reduction in power production is 0.147%.
	Cost of reduced power is: bhp x 0.00147 x 8,000 hrs/yr x 0.746 kW/bhp x 0.97 generator efficiency (kWh/yr)
	For landfill gas the power reduction is 0.161% because the higher volume of landfill gas per BTU supplied to the engine. Cost of power is $0.08/kWh for digester gas (cost of grid power) and $0.0425/kWh for landfill gas power (typical wholesale price based on price SCE paid for power from El Sobrante landfill [2002 contract]).
	Electrical costs for OCSD's pilot study were $1,200/yr.
9	OCSD's reduced engine maintenance was subtracted from its equipment maintenance for the pilot study. This cost is assumed to vary directly with horsepower.
10	The present worth value (PWV) is calculated for a project life of 20 years at an interest rate of 4%.
11	Baseline NOx is 36 ppmvd corrected to 15% O_2 for engines equal to or greater than 500 bhp and 45 ppmvd corrected to 15% O_2 for engines smaller than 500 bhp.
	Baseline VOC is 40 ppmvd corrected to 15% O_2 for landfill gas engines and 250 ppmvd corrected to 15% O_2 for digester gas engines.
	Baseline CO is 2000 ppmvd corrected to 15% O_2.
	Conversion of ppmvd corrected to 15% O_2 to g/bhp-hr was based on an engine efficiency of 33% (based on higher heating value), which was the average for biogas engines in the engine survey conducted for the 2008 amendment. This includes a correction of 3% greater volume of combustion products (corrected to 15% O_2) due to the CO_2 in the fuel.
	The emission reduction calculations assume 8,000 hrs/yr of engine operation.
12	The CO reductions are discounted by 1/7 due to its reduced ozone formation potential.

NOxTech System (20-year Equipment Life) – Costs provided by NOxTech

	Digester	Digester	Digester	Digester	Digester	Digester	Digester	Landfill	Landfill	Landfill	Landfill	Landfill	Landfill
BHP	4200	3471	1600	1350	1000	500	250	4200	3471	2700	2000	1500	1350
Installed Equipment, $													
Equipment Cost, $ (Note 1)	*960,000*	*800,000*	*400,000*	*400,000*	*400,000*	*400,000*	*400,000*	*960,000*	*800,000*	*800,000*	*400,000*	*400,000*	*400,000*
Installation Cost, $ (Note 2)	*250,000*	*200,000*	*100,000*	*100,000*	*100,000*	*100,000*	*100,000*	*250,000*	*200,000*	*200,000*	*100,000*	*100,000*	*100,000*
Installation Cost Contingency, $ (Note 3)	*300,000*	*300,000*	*300,000*	*300,000*	*300,000*	*300,000*	*300,000*	*0*	*0*	*0*	*0*	*0*	*0*
Project Management & Installation Supervision, $ (Note 4)	31,742	26,452	13,226	13,226	13,226	13,226	13,226	31,742	26,452	26,452	13,226	13,226	13,226
Total Initial Investment, $	**1,541,742**	**1,326,452**	**813,226**	**813,226**	**813,226**	**813,226**	**813,226**	**1,241,742**	**1,026,452**	**1,026,452**	**513,226**	**513,226**	**513,226**
Reactant, $/yr (Note 5)	37,952	31,365	14,458	12,199	9,036	4,518	2,259	37,952	31,365	24,398	18,073	13,554	12,199
Reduced Power Production, $/yr (Note 6)	68,365	56,499	26,044	21,975	16,277	8,139	4,069	53,041	43,834	34,098	25,258	18,943	17,049
Equipment Maintenance, $/yr (Note 7)	16,000	16,000	8,100	8,100	8,100	8,100	8,100	16,000	16,000	16,000	8,100	8,100	8,100
Total Annual Cost, $	**122,318**	**103,864**	**48,602**	**42,274**	**33,414**	**20,757**	**14,428**	**106,993**	**91,199**	**74,496**	**51,430**	**40,598**	**37,348**
Present Value of 20-yr Cost, $ (Note 8)	**3,204,042**	**2,737,965**	**1,473,728**	**1,387,724**	**1,267,319**	**1,095,312**	**1,009,308**	**2,695,780**	**2,265,852**	**2,038,847**	**1,212,161**	**1,064,947**	**1,020,783**
NOx Reduction, tpy (Note 9)	12.6	10.5	4.8	4.1	3	1.5	1	12.6	10.5	8.1	6	4.5	4.1
VOC Reduction, tpy (Note 9)	29	24	11.1	9.3	6.9	3.5	1.7	1.3	1.1	0.8	0.6	0.5	0.4
CO Reduction, tpy (Note 9)	538.9	445.4	205.3	173.2	128.3	64.2	32.1	538.9	445.4	346.4	256.6	192.5	173.2
CO Reduction/7, tpy (Note 10)	77.0	63.6	29.3	24.7	18.3	9.2	4.6	77.0	63.6	49.5	36.7	27.5	24.7
Cost Effectiveness, $ per ton of NOx+VOC+CO/7	**1400**	**1400**	**1600**	**1800**	**2200**	**3900**	**6900**	**1500**	**1500**	**1700**	**1400**	**1600**	**1700**
$/kW-hr	**0.007**	**0.007**	**0.008**	**0.009**	**0.011**	**0.019**	**0.035**	**0.006**	**0.006**	**0.007**	**0.005**	**0.006**	**0.007**

Notes for NOxTech System:

1	NOxTech provided the following cost information:
	Equipment cost for NOxTech unit sized for 1 engine at 1.5 MW max rating = $400,000. 2 units are required for engines greater than 1.5 MW and less than 3 MW = $800,000. A discount is offered for 3 or more units purchased simultaneously = $960,000 for engines greater than 3 MW.
	If a single unit treats multiple engines with a maximum total rating of 1.5 MW, the cost is $450,000.
	These installation costs are "turn-key." They are site-specific and depend on many factors. The installation costs provided by NOxTech are intended to be typical.
2	Installation costs, including urea tank, are $100,000 for 1 unit treating 1 engine up to 1.5 MW, $200,000 for 2 units treating engines greater than 1.5 MW and less than 3 MW, and $250,000 for 3 units treating engines greater than 3 MW.
	For a single unit treating multiple engines with a maximum total rating of 1.5 MW, the cost is $150,000.
3	EMWD's installation costs were $400,000 for the EGR system. There were also additional equipment and design costs reported that may be site-specific, depending on operating characteristics. The added engineering costs are not independently verifiable. As part of the demonstration project, EMWD incurred added design costs that are not anticipated to be included as a part of future off-the-shelf technology. The additional costs are presented here merely as a worst case and are not expected to be incurred by future end users. The added EGR costs do not apply to landfills because there is no expected natural gas supplementation that would necessitate an EGR system.
4	Project management and installation supervision is assumed to be the same ratio to non-catalyst installed equipment as the OCSD project. For the Interim Technology Assessment, this cost was estimated to be $36,000 for OCSD labor for project management and installation supervision of $1,096,000 of non-catalyst equipment cost. For OCSD's actual non-catalyst equipment cost, which was $1,875,129, the project management and installation supervision cost is approximately $62,000.
5	Reactant is urea. Stoichiometry is 1 pound of urea to treat 1 pound of NOx. Cost of urea is $1.50 per gallon based on information provided by NOxTech. Reactant cost is assumed to vary directly with horsepower.
6	Reduction in power production is caused by biogas use in NOxTech reactor and pressure drop across NOxTech system. Fuel use is assumed to be 5% of full-load engine fuel, and pressure drop is assumed to be 3"H2O. Calculated reduction in power production is 0.133%.
	Reduced power output is: bhp x 0.746 kW/bhp x 8,000 hrs/yr x 0.00133 x 0.97 generator efficiency (kWh/yr).
	It is assumed that use of 5% of full-load engine fuel in NOxTech chamber further reduces power by 5% in landfill gas case, but digester gas can be replaced by natural gas.
	Cost of reduced power is $0.08/kWh for digester gas case and $0.0425/kWh for landfill gas case. Cost of natural gas is $0.50 per them.
7	Information provided by NOxTech: annual maintenance for 1 NOxTech unit is estimated to be $8,100 and $16,000 for 2 or more units. The annual maintenance cost for 1 unit treating multiple engines with a maximum total rating of 1.5 MW is $10,000.
8	Same as Note 10 in previous table.
9	Same as Note 11 in previous table.
10	Same as Note 12 in previous table.

ATTACHMENT B

ORANGE COUNTY SANITATION DISTRICT CATALYTIC OXIDIZER/SCR PILOT STUDY FINAL REPORT, JULY 2011

Orange County Sanitation District
10844 Ellis Avenue • Fountain Valley CA 92708-7018

Retrofit Digester Gas Engine with Fuel Gas Clean-up and Exhaust Emission Control Technology

South Coast Air Quality Management District Contract #10114

Pilot Testing of Emission Control System Plant 1 Engine 1

Orange County Sanitation District Project No. J-79

FINAL REPORT

July 2011

Report Prepared By:

Malcolm Pirnie, The Water Division of ARCADIS

8001 Irvine Center Drive
Suite 1100
Irvine, CA 92618

The Water Division of ARCADIS

Contents

List of Tables

List of Figures

Appendices

Glossary of Terms

Acronym	Definition
ARB	Air Resources Board
AQMD	Air Quality Management District
BACT	Best Available Control Technology
bhp	Brake horse power
CEMS	Continuous emissions monitoring systems
CI	Compression Ignition
CO	Carbon monoxide
CO_2	Carbon dioxide
Cpsi	Cells per square inch
°C	Degrees Centigrade
°F	Degrees Fahrenheit
DG	Digester Gas
DGCS	Digester Gas Cleaning System
EPA	Environmental Protection Agency
FTIR	Fourier Transform Infrared
GC/MS	Gas chromatography-mass spectrometry
H_2S	Hydrogen sulfide
HHV	Higher Heating Value
HI	Hazard Index
hp	Horse power
HRU	Heat Recovery Unit
IC	Internal Combustion
in. w.c.	Inches water column
KW	Kilowatt
MDL	Method Detection Limit
MMscf	Million standard cubic feet
MW	Megawatts
N_2	Nitrogen
NG	Natural Gas
NMHC	Non-methane hydrocarbons
NMNEOC	Non-methane non-ethane organic compounds
NO_2	Nitrogen dioxide
NO_x	Nitrogen oxides
O_2	Oxygen
OCSD	Orange County Sanitation District
PEMS	Parametric Emission Monitoring System
PM	Particulate matter
ppbv	Parts per billion by volume
ppm	Parts per million
ppmv	Parts per million by volume
psig	Pounds per square inch gage
RPM, rpm	Revolutions per minute
SCAQMD	South Coast Air Quality Management District
SCAT	Synthetic gas matrix catalyst activity test
scfm	Standard cubic feet per minute

Acronym	Definition
SI	Spark-ignited
VOCs	Volatile organic compounds
XRF	X-ray fluorescence

Acknowledgements

This pilot study could not have been accomplished without the support and cooperation of the following people (listed in alphabetical order), as well as numerous others who contributed to the performance of the project.

South Coast Air Quality Management District

- Alfonso Baez
- Howard Lange
- Laki Tisopulos
- Charles Tupac

Orange County Sanitation District

- Randa AbuShaban
- Terry Ahn
- Kim Christensen
- James Colston
- David Halverson
- James Herberg
- Vladimir Kogan
- David MacDonald
- Lisa Rothbart
- Nguyen Thomas
- Edward Torres
- Don Van Voorst
- Trimbak Vohra

Malcolm Pirnie, Inc.

- Phyllis Diosey
- Joseph Krupa
- Kit Liang
- Dennis Papastathis
- Sarina Sriboonlue
- Daniel Stepner

Executive Summary

The Orange County Sanitation District (OCSD) owns and operates two wastewater treatment plants in Orange County, California, Reclamation Plant No. 1 (Plant 1) in Fountain Valley and Treatment Plant No. 2 (Plant 2) in Huntington Beach. Each plant operates a Central Power Generation System (CGS) to produce electrical power for the plant operations using large digester gas-fired internal combustion (IC) engines. Plant 1 has three (3) 2.5-megawatt (MW) internal combustion (IC) engines and Plant 2 has five (5) 3-MW IC engines, fueled primarily by digester gas (a biogas) and supplemented by small amounts of natural gas.

Plants 1 and 2 are within the jurisdiction of the South Coast Air Quality Management District (SCAQMD). SCAQMD has established regulations aimed at reducing and controlling air emissions from combustion sources, such as the engines at the plant CGS, including Rule 1110.2 *Emissions from Gaseous and Liquid-fueled Internal Combustion Engines*. In February 2008, SCAQMD amended Rule 1110.2, lowering the emission limits for nitrogen oxides (NOx), volatile organic compounds (VOCs), and carbon monoxide (CO) for IC engines. The amended rule also requires biogas-fueled engines to meet new lower NOx, CO, and VOC emission limits effective July 2012.

In April 2008, OCSD engaged Malcolm Pirnie to conduct an emission reduction technology evaluation of the CGS engines in order to identify technologies for reducing NOx, CO, and VOC emissions to meet the new Rule 1110.2 emission limits, including combustion modification and post-combustion control. After a detailed review of different technologies, the post-combustion technology of catalytic oxidizer/selective catalytic reduction (Cat Ox/SCR) system with digester gas cleaning system (DGCS) using carbon adsorption was recommended as the technology with the most potential for meeting the future Rule 1110.2 emission limits. OCSD then embarked on a full-scale pilot study of the recommended technology on Engine 1 at Plant 1 to evaluate if the future amended Rule 1110.2 limits can be met for their digester gas-fired IC engines. Because SCAQMD recognized that the future emission limits in amended Rule 1110.2 were “technology-forcing,” the Governing Board directed staff to conduct a technology assessment to determine if cost-effective and commercially available technologies exist that can achieve these new lower emission limits. SCAQMD issued a grant to OCSD in 2009 (*SCAQMD Contract #10114*) to support the pilot test study at Plant 1 Engine 1, and the operation of the pilot study was granted a Permit to Construct/Operate for an Experimental Research Project by SCAQMD (Application Number 497717) in November 2009. The construction and installation of the pilot study equipment commenced in October 2009; the pilot study testing officially began on April 1, 2010 and officially ended on March 31, 2011.

Under the pilot study, Engine 1 at Plant 1 was equipped with a catalytic oxidizer to remove CO and VOCs, followed by an SCR system with urea injection to remove NOx (both systems supplied by Johnson Matthey). Due to space limitations at Plant 1, the catalytic oxidizer and SCR systems were mounted on a platform 14 feet above an onsite access road. Engine 1 is fueled primarily by digester gas, supplemented by natural gas. Digester gas contains low concentrations of siloxanes and other compounds which convert to sand-like particulate during combustion (silica) that contribute to rapid degradation of engines, gas turbines, and boilers, along with increased maintenance requirements. In addition, the silica also adheres to the catalyst media of the post-combustion control equipment. Therefore, a digester gas cleaning system (DGCS) was installed (supplied by Applied Filter Technology) to remove these contaminants from the digester gas before it was combusted in Engine 1. The potential for carbon media breakthrough was routinely monitored for using Draeger® tubes to measure hydrogen sulfide (H_2S) concentrations. Samples of the digester gas before and after the DGCS were also sent for laboratory analysis to measure for siloxane, H_2S, and VOCs that could indicate media breakthrough. During the study, inlet and outlet concentrations of CO, NOx, and VOCs were measured to determine the potential reductions in emissions due to the Cat Ox/SCR system. Sampling methods included:

- CO: Portable analyzer, SCAQMD Method 100.1
- VOCs: SCAQMD Methods 25.1/25.3
- NOx: Portable analyzer, SCAQMD Method 100.1
- Aldehydes: Modified CARB Method 430, SCAQMD Method 323 (formaldehyde)
- Ammonia slip (free ammonia): Modified SCAQMD Method 207.1 and Draeger® tubes

In addition, data from the OCSD's continuous emissions monitoring system (CEMS) was collected at the engine exhaust (inlet to the Cat Ox system) for NOx and at the stack exhaust for NOx, CO, and O_2. All CEMS data is based on 15-minute averages. Sampling was also performed for formaldehyde, acetaldehyde, and acrolein as required by the Experimental Research Project permit. In addition, ammonia levels in the stack exhaust were also measured to quantify potential ammonia slip, a result of the urea injection used in the SCR system. The overall conclusions of the pilot study are as follows:

1. The average NOx concentration at the stack exhaust after the pilot study controls was approximately 7 ppmv, below the 11 ppmv required under amended Rule 1110.2. The lowest NOx stack exhaust concentration met consistently under all valid conditions was 16 ppmv. While there were some periods (i.e., 15-minute block averages) where the NOx stack exhaust concentration was above 11 ppmv, after screening these periods, 181 periods out of 21,285 total operating periods (approximately 5,321 hours) remained as valid NOx excursions above the new Rule

1110.2 limit. These periods occurred during 61 separate events and accounted for less than 0.9% of the total measurement periods during the pilot study. Excursions were considered valid when they occurred during periods/events when the percentage of natural gas increased to above 5% of the fuel blend, when engine loads exceeded the loads mapped during the SCR system commissioning, or during periods/events not attributable to engine start-up or operational /system adjustments. An implication of these remaining periods are that the 11 ppmv limit is too conservative an emission limit, and may warrant further evaluation and potential increase and/or a specified percentage of allowable excursions.

2. SCR systems similar to the Johnson Matthey® system used in the present pilot study are commercially available for combustion units fueled by single component fuels, such as natural gas. Although the SCR system did not consistently meet the 11 ppmv limit with the digester gas/natural gas fuel blend in the pilot study, it did demonstrate a significant reduction in NOx emissions.
3. The free ammonia concentration was below 0.5 ppmv during all testing events using either SCAQMD compliance method 207.1, and below the Method Detection Limit (MDL) using Draeger® tubes.
4. The maximum CO concentration at the stack exhaust using the CEMS data was 42.2 ppmv, well below the amended Rule 1110.2 emission limit of 250 ppmv.
5. The maximum VOC concentration at the stack exhaust was found to be 4.95 ppmv, and was consistently well below the 30 ppmv limit in amended Rule 1110.2.
6. The use of the combined Cat Ox/SCR system in the pilot study resulted in significant reductions in CO, VOC, and NOx.
7. The DGCS system, in general, removed siloxanes from the digester gas to below Method Detection Limit (MDL) levels and significantly reduced sulfur compounds and VOCs successfully reducing catalyst masking which should lead to extended catalyst life. Additional benefits of the contaminant removal were significant improvements in engine maintenance requirements and lower O&M costs.
8. The total capitals cost to design, procure, and install a digester gas cleaning vessel to clean all the digester gas to the three Plant 1 engines, and a Cat Ox/SCR system with auxiliary equipment for Engine 1 is estimated to be $2,300,000. The annual operations and maintenance (O&M) cost for these systems at Plant 1 is approximately $59,000. Assuming a 20-year lifespan, the total annualized cost (capital cost plus O&M) for the DGCS and Cat Ox/SCR systems for Plant 1 Engine 1 is $227,000.
9. The cost effectiveness analysis (based on dollars per ton of NOx, VOC, and CO emissions reduced) was developed for two scenarios: Scenario 1 assumed that the uncontrolled emissions were developed based on current permit limits (i.e., 45 ppmv, 209 ppmv, and 2,000 ppmv, respectively), and Scenario 2 assumed that the uncontrolled emissions were developed based on the results from the 2011 Annual Compliance Test for Engines 2 and 3. Both scenarios assumed that the controlled emissions were based on the Rule 1110.2 limits of 11 ppmv for NOx and 30 ppmv

for VOCs, and the pilot testing results of 15 ppmv for CO. Under these assumptions, the cost effectiveness for Scenarios 1 and 2 is $7,987 and $17,585, respectively, per ton of NOx plus VOCs reduced. The cost effectiveness for Scenarios 1 and 2 is $636 and $3,546, respectively, per ton of CO reduced. Note that the cost effectiveness for CO is conservative since the annualized cost is based on the entire system including the SCR and urea injection system. The annualized cost and emissions reduced calculations were based on operating each engine for a maximum of 6,000 hours per year.

1. Project Background and Objectives

1.1. Background

The Orange County Sanitation District (OCSD) owns and operates two (2) wastewater treatment plants that serve 21 cities and three special districts in the central and northwest Orange County, California, Reclamation Plant No. 1 (Plant 1) in Fountain Valley and Treatment Plant No. 2 (Plant 2) in Huntington Beach. In addition to the wastewater treatment processes, each plant operates a Central Power Generation System (CGS) to produce electrical power for the plant operations using large digester gas-fired internal combustion (IC) engines. Plant 1 has three (3) 2.5 megawatt (MW) internal combustion (IC) engines and Plant 2 has five (5) 3 MW IC engines, fueled primarily by digester gas (a biogas) and supplemented by small amounts of natural gas. Biogas, a by-product of the anaerobic digestion of wastewater solids, is classified as a renewable fuel, and the combustion of the biogas in the IC engines provides a beneficial reuse of a waste product.

Plants 1 and 2 are within the jurisdiction of the South Coast Air Quality Management District (SCAQMD). SCAQMD has established regulations aimed at reducing and controlling air toxic emissions from combustion sources, such as the engines at the plant CGS, including Rules 1110.2, 1401 and 1402. Under Contract J-79 Air Toxics Emission Reduction Strategic Plan (2003), Malcolm Pirnie was retained by the OCSD to perform an evaluation of regulations addressing air toxic requirements under the rules. Malcolm Pirnie prepared an emission reduction study/air toxics strategic plan for the OCSD to comply with the NOx emission limit under Rule 1110.2 for IC engines. The study also addressed acceptable risk levels from Plant 1 and Plant 2 to comply with Rules 1401 and Rule 1402 (*Air Toxic Emission Reduction Strategic Plan* (Malcolm Pirnie, 2004) and *2012 Air Toxic Emission Reduction Strategic Plan* (Malcolm Pirnie, 2006)). The study identified the formaldehyde emissions from the CGS engines as a significant contributor to the overall risk levels, and also identified a catalytic oxidizer system with a digester gas cleaning system (DGCS) as a viable control technology to reduce the formaldehyde emissions from the digester gas-fired IC engines. This system was evaluated in a full-scale pilot study of a catalytic oxidizer system on Engine 3 at Plant 2 (*Catalytic Oxidizer Pilot Study* (Malcolm Pirnie, 2007)).

A catalytic oxidizer system is one of the most promising technologies for controlling carbon monoxide (CO) and volatile organic compounds (VOC) emissions from combustion units burning natural gas. However, fouling or rapid performance degradation of the catalytic oxidizers has been an issue for engines burning digester gas due to contaminants in the digester gas, such as volatile methyl-siloxanes and sulfurous compounds that tend to foul the catalytic oxidizers. Therefore, the use of a digester gas cleaning system to prevent the contaminants in the digester gas from fouling and/or masking the catalyst was also evaluated.

In February 2008, SCAQMD further amended Rule 1110.2 to reduce emission limits for nitrogen oxides (NOx), VOCs, and CO, and also to improve/enhance monitoring, recordkeeping and reporting requirements for IC engines. Biogas engines were given until July 2012 to meet new lower emission limits. Malcolm Pirnie conducted an emission reduction technology evaluation of the CGS engines and identified several technologies for reducing NOx, CO, and VOC emissions, including combustion modification and post-combustion control (*Feasibility Study for a Technology Evaluation for Compliance with Amendments to SCAQMD Rule 1110.2 – Emissions from Gaseous and Liquid-fueled Internal Combustion Engines* (Malcolm Pirnie, 2008)). After a detailed review of the different technologies, the post-combustion technology of catalytic oxidizer/selective catalytic reduction (Cat Ox/SCR) system with DGCS using carbon adsorption was recommended as the technology with the most potential for meeting the future Rule 1110.2 emission limits.

In 2009, OCSD embarked on a pilot study of this recommended technology on Engine 1 at Plant 1 to evaluate if the future Rule 1110.2 limit can be met for their biogas-fired IC engines. Design of the pilot system included an SCR system for NOx emission reduction, an oxidation catalyst unit for CO and VOC reduction (including formaldehyde), and a DGCS upstream from the IC engines for removal of siloxanes to prevent fouling of the catalysts. Additional benefits of the DGCS include the removal of total reduced sulfur and total volatile organic compounds. To supplement and support this study, SCAQMD issued a grant to OCSD (SCAQMD Contract #10114, 2009) for this pilot test study, and will be evaluating the data collected as part of their technology assessment of the feasibility of biogas engines achieving the future Rule 1110.2 emission limits for biogas-fired engines. The operation of the pilot study was granted a Permit to Construct/Operate for an Experimental Research Project by SCAQMD (Application Number 497717) (Appendix A-1).

1.2. SCAQMD Rule 1110.2

The IC engines at OCSD are subject to Rules 1110.2. Rule 1110.2 provides emission limits and monitoring requirements for all stationary and portable engines over 50 brake-horsepower (bhp). Rule 1110.2 (*Emissions from Gaseous- and Liquid- Fueled Engines*) was promulgated to reduce the NOx, CO and VOC emissions from engines over 50 bhp. On February 1, 2008, Rule 1110.2 was amended in order to achieve further emissions reductions from stationary engines based on the cleanest available technologies. Under the February 2008 amendments to Rule 1110.2 shown below, more stringent NOx, CO, and VOC limits were adopted, to become effective for biogas-fueled engines in July 2012 provided a technology assessment confirms that the limits below are achievable.

- NOx limit was lowered from 36 ppm (or ~ 45 ppm*) to 11 ppm at 15% O_2.
- VOC limit was lowered from 250 ppm* to 30 ppm at 15% O_2.
- CO limit was lowered from 2,000 ppm to 250 ppm at 15% O_2.

* Existing limits allow for an alternative emission limit for OCSD engines based on the engine efficiency correction factor.

The rule allows for some exemptions, including an exemption during engine start-up, to allow for sufficient operating temperatures to be reached for proper operation of the emission control equipment. The start-up period is limited to 30 minutes unless a longer period is approved for a specific engine by the Executive Officer and is made a condition of the engine permit.

1.3. Objectives

Because the future Rule 1110.2 emission limits shown above are "technology-forcing," the SCAQMD Governing Board directed staff to conduct a technology assessment to determine if cost-effective and commercial technologies are available to achieve their limits. This pilot study will be used by SCAQMD as part of that technology assessment to evaluate the ability of the biogas-fueled engines at OCSD wastewater treatment plants to meet these future limits.

The objective of this study is to evaluate the effectiveness of a Cat Ox/SCR system with a DGCS as a post-combustion emissions control technology for an IC engine operating on biogas at a wastewater treatment plant. The data collected will be evaluated as part of the technology assessment study for the 2012 biogas engine emission limits under amended Rule 1110.2. Data were gathered on engine performance and emission reductions. Data were also gathered to obtain information for use in full-scale design (e.g., back pressure, impact on heat recovery unit (HRU)), to assess the performance of the DGCS (e.g., siloxane removal, media life), and to determine the economic feasibility of operating the Cat Ox/SCR system and the DGCS.

1.4. Report Organization

This report is organized into the following sections:

- Executive Summary
- Section 1. Project Background and Objectives
- Section 2. Pilot Study Work Plan
- Section 3. Results and Discussion
- Section 4. Cost Effectiveness Analysis
- Section 5. Conclusions and Recommendations

- Appendices

2. Pilot Study Work Plan

2.1. General Description

The engines at the CGS at both the Fountain Valley Reclamation Plant 1 and Huntington Beach Treatment Plant 2 are lean-burn, spark-ignited IC engines, and have been permitted to operate by SCAQMD. Plant 1 has three (3) 2,500 kilowatts (KW) units, while Plant 2 has five (5) 3,000 KW units. The engines are of conventional four-stroke cycle stationary Vee engine construction. They utilize spark-ignited pre-chamber technology to achieve extremely low NOx emissions. These electrical power generation stations utilize state-of-the-art low emission, spark-ignited, reciprocating engines fueled by digester gas and/or natural gas to drive generators. The engine generators normally operate in parallel with the grid, providing electrical loads at both plants. Excess power at Plant 2 is exported to the local utility. Waste heat energy in the cooling systems and exhaust are extracted and utilized for process heating through heat recovery units on each engine. Plant 2 has the capability to produce additional electrical energy with waste heat energy through use of a steam turbine-generator. Typically, at any given time one unit is down at Plant 1 and two units are down at Plant 2 for maintenance while the remaining units operate over a range of 60-120% load. Once placed on line, an engine will operate approximately 1,000-2,000 hours before being shut down for routine maintenance.

At Plant 1, each of the three IC engines are rated at 3,471 bhp, and each engine can produce up to 2.5 MW of electricity. This pilot study was conducted on Engine 1 at Plant 1 (see Figure 2-1). Details of the three Plant 1 engines, including Engine 1 are shown in Table 2-1.

Based upon a carefully designed series of studies performed for OCSD to meet existing and emerging regulatory standards, the full-scale pilot study of Engine 1 at Plant 1 included a DGCS using carbon media for removal of siloxanes and other harmful contaminants from the digester gas, and post-combustion control technology using a catalytic oxidizer system to reduce emissions of CO and VOCs, and SCR technology with urea injection for controlling of NOx emissions. The engine is equipped with continuous emissions monitoring system (CEMS) at the engine exhaust for measuring NOx concentration entering the Cat Ox/SCR system, and at the stack for measuring NOx, CO, and oxygen (O_2) concentrations after the Cat Ox/SCR system. Figure 2-2 and Appendix A-2 shows a schematic of the overall system.

Construction of the pilot study was initiated in October 2009. During the design and construction for the pilot study, two other projects were also in progress at Plant 1:

- J-79-1 Central Generation Automation. During this project, the engine control systems (ECS) for the CGS at both plants were replaced. The existing ECS at both facilities were no longer being manufactured and parts replacement was not reliable. The new systems provide automatic load management capability, as well as an emissions monitoring feedback signal for exhaust emissions control.

- J-79-1A Continuous Emissions Monitoring Systems. Installation of a CEMS at the stack outlets of the CGS engines at both plants and NOx inlet analyzers.

Prior to the start of the full-scale pilot study, both J-79-1 and J-79-1A projects were completed at Plant 1 Engine 1 before the pilot system commenced operation in April 2010 and initial performance testing was performed on both the DGCS and Cat Ox/SCR system.

2.2. Digester Gas Cleaning System

Digester gas is generated during the anaerobic digestion of the sewage sludge produced during the wastewater treatment process. This biogas contains contaminants such as hydrogen sulfides (H_2S), VOCs, and low concentrations of volatile siloxane compounds. Siloxane is a compound that is found in numerous consumer personal products and thus enters the wastewater treatment system. During combustion, the siloxanes convert to silica, sand-like particulate that deposit on the surfaces of combustion equipment contributing to a rapid degradation of engines, gas turbines, and boilers, along with increased maintenance requirements. In addition, the silica also adheres to the catalyst media of any post-combustion control equipment. These deposits can cause masking of the catalyst sites that significantly reduces the effectiveness of the catalyst. Based upon the pilot testing performed at Plant 2 (Malcolm Pirnie, 2008), the DGCS was shown to be successful in removing contaminants such as siloxanes, H_2S, and VOCs from the digester gas, and extending the catalyst performance life comparable to an IC engine combusting natural gas. In addition, the use of the DGCS resulted in a significant reduction in operations and maintenance (O&M) costs for the CGS engines.

2.2.1. DGCS Technology and Equipment

In order to minimize the masking effect from the siloxanes and sulfurous compounds, and prevent the deterioration of the post-combustion Cat Ox/SCR system installed for the pilot study, the digester gas was scrubbed to remove these contaminants prior to combustion. A DGCS (SAG™) supplied by Applied Filter Technology, Inc. (AFT) and consisting of a single carbon media vessel was installed at Plant 1. The SAG™ process was developed to remove siloxanes and other contaminants considered harmful to power generation equipment including engines, gas turbines, fuel cells and boilers. The media also treats VOCs, H_2S, and other sulfides. The vessel contains three layers of specialized graphite-based molecular sieves, which are small to large black pellets or spheres, capable of removing, through adsorption, the siloxanes from the biogas. The sieve types and layer depths (and the resulting vessel size) are determined by gas analysis to confirm system performance parameters. The biogas enters the SAG™ vessel at the top and proceeds down through the layers of sieves, exiting through flanged septa connected to a manifold header. Each layer removes a specific type of contaminant and, in turn, protects the layer following it by removing contaminants that can foul it. The SAG™ siloxane media is a loose pellet form of polymorphous graphite carbon-based media specifically designed for removal of siloxanes in methane, and can be disposed of as a non-hazardous waste at a local approved site. Following system start-up, the vessel is allowed to process the biogas until there is breakthrough. In the present pilot study, the potential for media breakthrough was conservatively determined using H_2S as a marker. Once the potential for breakthrough is determined, the media is scheduled for change out. The vessel is then taken out of service, the media is replaced, and the vessel is returned to service.

The SAG™ unit used in the pilot study was a single stage, 7.5 ft diameter by 8 ft straight -sided dished downflow carbon steel filter unit. The unit contained 9,900 lbs of SAG™ three-stage media for siloxane removal. It includes interior high build epoxy coating and corrosion allowance vessel plate thickness. The DGCS system was sized and designed such that it could be used to clean all the digester gas produced at Plant 1. The DGCS was designed for the conditions presented in Table 2-2.

The DGCS was located along the south side of the Gas Compressor Building. Figure 2-3 shows a photograph of the DGCS at the Plant 1.

2.2.2. DGCS Measurement and Monitoring Methods

One objective of this pilot study was to assess the performance of the DGCS with respect to the removal of siloxanes and other contaminants, along with the life of the removal media. Based on the pilot testing performed at Plant 2 Engine 3, the DGCS proved successful in removing contaminants from the digester gas. The catalyst at Plant 2 Engine 3 fouled rapidly after combustion of uncleaned digester gas. Catalyst performance with the DGCS was comparable to that of a catalyst installed on the exhaust of an IC engine operating on natural gas.

Testing was performed to determine if the equipment met the design specifications. Two sampling methods are commonly used for measuring siloxanes: gas chromatography-mass spectrometry (GC/MS) and the wet chemistry method. Digester gas analyzed using GC/MS can be collected using either Tedlar® bags or canisters. The wet chemistry method requires samples to be collected using methanol impingers over a two to four hour sampling period, and then sent to a lab for analysis. After discussions with several certified laboratories, and review of several published papers, both methods were found to have merit; however, the collection of the samples using Tedlar® bags for measurement by GC/MS provided the most flexibility for minimum sampling time and equipment required. In the initial performance testing of the gas cleaning system, samples were collected using Tedlar® bags, canister, and methanol impinger methods at the digester gas inlet location at the same time, during the same day, and the analytical results were compared to determine the most appropriate method for analyzing performance breakthrough. During the initial test, individual measurements of inlet total siloxane, consisting of, hexamethylcyclotrisiloxane (D3), octamethylcyclotetrasiloxane (D4), decamethylcyclopentasiloxane (D5), hexamethyldisiloxane (L2), octamethyltrisiloxane (L3), and any other siloxane compounds identifiable according to the test method, were recorded.

For the sampling performed using Tedlar® bags at the DGCS inlet, the samples were collected and sent to a certified laboratory for the analysis of speciated siloxanes using TO-14/15, speciated VOCs using TO-15, total reduced sulfides using EPA 1023 Method 16B, or ASTM Procedure D-5504 GC/SCD, and the overall gas components and quality (% CH_4, % CO_2, % N_2, heating value using) using EPA Method 3C. One sample was also collected at the DGCS outlet to confirm that the DGCS met performance standards for all siloxanes to be measured as non-detect (i.e., below Method Detection Limit, MDL).

Samples were also collected in SUMMA® canisters at the DGCS inlet and sent to a certified laboratory for analysis of speciated siloxanes. In addition, speciated VOCs were analyzed using TO-15, total reduced sulfides were analyzed using ASTM D-5504, and overall gas components and quality (% CH_4, % CO_2, % N_2, heating value) was analyzed using ASTM D-1946.

The wet chemistry method was used at the DGCS inlet. During the test, the digester gas sample was collected using methanol impingers over a 4-hour period, and the samples were sent to the laboratory for individual measurements of inlet total siloxane.

Hydrogen sulfide testing was conducted weekly using Draeger® tubes. The H_2S concentration was used as an indicator that the media was nearing saturation. Breakthrough itself was determined to occur when the total siloxane concentration at the outlet of the carbon adsorber was above the MDL or when the H_2S concentration reached 15 ppm. Originally, the monitoring plan recommended by the vendor, AFT, was to use an H_2S concentration threshold of 5 ppm at the outlet to trigger siloxane and siloxane compound testing every week until breakthrough occurred. However, a more conservative approach for media saturation was used for the pilot study. Saturation and media replacement was triggered when measurable H_2S levels (generally around 1 ppm) were found using the Draeger® tube readings. The procedures used for taking the Draeger® tube measurements are shown in the Monitoring Test Procedure in the CD attached to this report. OCSD staff also performed routine sampling of the digester gas for H_2S (Draeger® tubes), sampling for reduced sulfides (SCAQMD Method 307-91), and sampling for speciated VOCs (TO-15).

2.2.3. Selection of DGCS Sampling Method

Details of the DGCS performance test are presented in a Technical Memorandum (Malcolm Pirnie, May 5, 2010) found in Appendix A-3. Table 2-3 summarizes the results of the comparison of siloxane sampling methods.

As shown in the summary of the results shown in the table, the Tedlar® bag sampling method detected the highest level of total siloxane. In addition, the Tedlar® bag sampling method provided the most flexibility for minimum sampling time and equipment required. Based on these criteria, the Tedlar® bag method was chosen as the sampling method for the digester gas sampling for siloxanes.

2.3. Cat Ox/SCR System

Based on the results of the Catalytic Oxidizer Study on Plant 2 Engine 3 (Malcolm Pirnie, 2007) and the Feasibility Study (Malcolm Pirnie, 2008), the combination of a catalytic oxidizer followed by selective catalytic reduction equipment with urea injection provided by Johnson Matthey (JM) was selected for the pilot study.

Catalytic oxidation is a post-combustion control technology which has been commercially proven to reduce CO, VOCs and air toxics, including formaldehyde and acrolein, from engines burning natural gas. There is, however, limited performance data for an engine fired with digester gas, either with or without a gas cleaning system. The digester gas, which is generated during the biological consumption of solids that are collected during the wastewater treatment process, contains low but detrimental concentrations of siloxane compounds, which convert to silica during combustions and deposit on the surfaces of post-combustion equipment, including catalyst media. This fouling of the catalyst, or catalyst masking, significantly reduces the effectiveness of the catalyst. In order to minimize this masking effect, the digester gas can be pre-cleaned to remove these siloxanes prior to combustion.

The Johnson Matthey catalyst elements are manufactured in a “block” form. The catalyst block substrate is made from stainless steel foil that is retained by a stainless steel frame. This structure undergoes a proprietary coating process in which the foil is chemically treated to increase surface area. Active platinum group metal catalysts are then applied. The coating, catalyst composition, and honeycomb pore size were designed by Johnson Matthey to provide optimum durability and pollutant removal efficiency for the specified operating environment.

In the SCR system, the exhaust enters a mixing tube where a stream of atomized urea is introduced into the gas. The urea quantity is controlled by the urea injection control system. Mixing vanes distribute the atomized particles throughout the exhaust gas. Ammonia is formed from aqueous urea ($(NH_2)_2CO$) after the urea injection, which involves evaporation of water, thermal decomposition of urea, and finally hydrolysis of iso-cyanic acid. Evaporation of water is initiated when the aqueous urea is injected into the exhaust gas pipe. This mixture then enters the SCR housing. A chemical reaction between the ammonia from the urea, the exhaust gas NOx component, and SCR catalyst results in the reduction of the NOx into nitrogen (N_2), carbon dioxide (CO_2), and water (H_2O). The basic equations are:

Urea Reaction
$(NH_2)_2CO \rightarrow NH_3 + HNCO$
$HNCO + NOx + O_2 \rightarrow N_2 + H_2O + CO_2$

Ammonia Reaction
$NH_3 + NOx + O_2 \rightarrow N_2 + H_2O + CO_2$

The percent reduction of NOx is determined by the amount of urea introduced into the gas flow.

The Cat Ox/SCR system was installed in a horizontal position on a platform, elevated at a height of approximately 14 feet directly west of Engine 1 at Plant 1. This platform-mounted installation allowed for easy access to the equipment and access to the roadway underneath the platform. Figure 2-4 shows a photograph of the platform installation. The Cat Ox/SCR system was designed for the conditions and performance guarantees presented in Tables 2-1 and 2-4, respectively.

2.3.1. SCR/Catalytic Oxidizer System Technology and Equipment

Oxidation Catalyst Housing. The oxidation catalyst consisted of one Johnson Matthey Model 4040SS-4-30/36 housing for the catalyst at Engine 1. The housing has access doors on both sides of the housing, with four tracks for installing catalyst. One of the tracks houses the initial catalyst supplied, with three tracks available for later expansion if needed. There is a 30-inch flange on the inlet and a 36-inch flange on the outlet of the housing. When completely full of catalyst (4 layers), the total weight of the housing plus the catalyst is about 8,190 pounds. The housing has a number of two ¾ inch ports on the inlet and two ¾ inch ports on the outlet of the oxidation catalyst housing.

Oxidation Catalyst. A total of sixteen (16) whole oxidation catalyst blocks were part of this system. They were arranged 4 blocks wide x 4 blocks high x 1 block deep. [A whole block is approximately 2 feet wide x 2 feet tall x 3¼ inches deep and constitutes approximately 1 ft^3 of catalyst volume.] The cell density of this catalyst is 200 cells per square inch (cpsi). Figure 2-5 shows a photograph of the catalyst.

SCR Catalyst Housing. Johnson Matthey provided a JM Model 4040SS-4-36 housing for the catalyst. The housing was fabricated in 304 stainless steel. Two layers of catalyst were installed and there were two open tracks for addition of another layer if desired at a later date. The housing was equipped with access doors on both sides of the housing.

There are 36-inch inlet and outlet flanges (150# ANSI) provided on the housing. When completely full of catalyst (4 layers), the total weight of the housing plus the catalyst is approximately 8,190 pounds. The housing has a number of two ¾ inch ports on the inlet and two ¾ inch ports on the outlet of the SCR housing for sampling.

SCR Catalyst. The catalyst consists of thirty-two (32) whole SCR catalyst blocks on 200 cpsi metal substrate. They are arranged 4 blocks wide x 4 blocks high x 2 blocks deep. [A whole block is approximately 2 feet wide x 2 feet tall x 3¼ inches deep, and constitutes approximately 1 ft^3 of catalyst volume.]

Urea Injection Control System. This system was designed to control the injection rate of urea into the SCR based on engine load for one fuel blend. During the initial commissioning of the system, the engine load, the urea injection rate, and the NOx and ammonia outlet concentrations were measured and mapped. Mapping refers to the process in which the urea injection rate is correlated to the engine load in order to meet the desired NOx exhaust concentration. The system allowed for up to 25 combinations of engine load versus urea injection rate (set points).

In addition to the load map control, the injection system also uses a system of bias set points to trim the urea injection. The NOx curve bias is a percentage that can be input by the operator to increase or decrease the urea injection rate. This bias is typically set to 0%, but can be modified if engine operation is expected to change the NOx produced in the exhaust emissions. The NOx add bias increases the urea injection rate by an input gallon per hour setting based on the NOx outlet concentration from the stack exhaust CEMS analyzer. When the NOx outlet concentration reaches the level set in the control system, the urea injection rate will increase by the bias set point. The NOx subtract bias decreases the urea injection rate in the same manner. For the pilot test, no NOx subtract bias was set.

The SCR process requires precise control of the urea injection rate. An insufficient injection may result in unacceptably low NOx conversions. An injection rate that is too high can result in release of excessive ammonia emissions. These excess gaseous ammonia emissions are known as “ammonia slip”. Under the research permit for this study, the maximum allowable ammonia slip is 10 ppm. Excess ammonia can lead to clogging and equipment problems in downstream equipment. In addition, emissions of ammonia slip to the atmosphere can result in odors and a visible plume. The ammonia slip increases at higher NH_3/NOx ratios. The stoichiometric NH_3/NOx ratio is approximately 1.

2.3.2. Cat Ox/SCR Measurement and Monitoring Methods

Preliminary Testing/SCR Urea Injection Mapping. The objective of the preliminary testing was to measure the performance of the system at varying loads and fuel blends (i.e., digester gas and natural gas), and to map the urea injection system. The CO, NOx, and O_2 concentrations at varying engine loads and fuel distributions at the inlet of the oxidation catalyst and the outlet of the SCR catalyst were monitored for a period of six (6) hours at ten (10)-minute intervals using the TESTO® 350 XL Portable Monitor during startup as part of the preliminary testing. In addition, ammonia measurements were taken at the outlet of the SCR catalyst at ten (10)-minute intervals using Draeger® tubes. A data logger was used to monitor temperature and pressure differential on a real-time basis over the six (6)-hour testing period. Carbon monoxide was also monitored with the TESTO® 350 XL Portable Monitor. Load and fuel distribution of the engine were varied according to the schedule shown in Table 2-5. The recorded data is provided in Appendix C-1.

A secondary objective of the preliminary testing was to provide varying load and fuel scenarios for Johnson Matthey to map the urea injection system. A description of the SCR urea injection mapping during the pilot test is provided in a technical memorandum in Appendix A-4. Figure 2-6 presents a mapping diagram of the urea injection rate designed for a 95% digester gas to natural gas fuel blend during the pilot testing period after system adjustments were made on June 8, 2010.

Source Testing Using Compliance Methods. Source testing using SCAQMD compliance methods was performed after preliminary testing of the Cat Ox/SCR system and equipment startup and commissioning in order to measure the emissions of the system. The following summarizes the source testing using compliance methods performed on April 7-8, 2010:

- The initial testing using compliance methods was performed for one fuel blend (95% digester gas and 5% natural gas)
- Source testing was performed to sample for CO, NOx, VOCs, ammonia, and aldehydes (formaldehyde).
- SCAQMD Method 100.1 was used to measure NOx, CO, CO_2, and O_2 concentrations, modified CARB Method 430 was used to measure aldehydes (i.e., formaldehyde), Method 25.3 was used to measure total non-methane non-ethane organic compounds (NMNEOC), and modified SCAQMD Method 207.1 was used for measuring ammonia.

Table 2-6 describes details of the April 2010 initial test program using compliance methods.

2.4. Pilot Study Test Program Timeline

Table 2-7 presents the pilot study project timeline. The full equipment commissioning took place between March 23 and April 1, 2010. The pilot testing was conducted from April 1, 2010 through March 31, 2011. Since Engine 1 is used to provide power to the plant, it continued operation throughout the construction and commissioning of the system, with occasional stoppages as needed by the present study as well as the J-79-1 and J-79-1A projects.

Table 2-1:
Engine 1 Design Parameters

Manufacturer:	Cooper-Bessemer
Model:	LSVB-12-SGC
Cycle:	4-stroke
Bore:	15½ in
Stroke:	22 in.
Configuration:	Vee-12
Rated Speed:	400 RPM
Rated Output:	2,500 KW
BMEP:	138 psi
Horsepower	3,471 bhp
Load	100%
Operating Hours per Year	Up to 8,760
Type of Fuel	Cleaned Digester Gas / Natural Gas
Design Exhaust Flow Rate	27,555 acfm
Design Exhaust Temperature	800°F

Table 2-2:
DGCS Design Specifications

Gas Description	Anaerobic digester gas
Flow	1440 scfm
Pressure drop per foot of media	0.5 in. w.c.
Pressure drop total with piping	7.5 in. w.c
Pressure - actual	58 psig inlet (actual)
Pressure - design	150 psig
Maximum gas inlet Temperature	70°F
Maximum Ambient Temperature	100°F
Minimum Ambient Temperature	40°F
Humidity	Saturated at 70°F
Siloxane – design	5 ppm
Siloxane – current	5 ppm
Total Reduced Sulfur (H_2S) - design	50 ppm
Total VOC – design	50 ppm
Siloxane removal	Below best available detection limit at time of testing (i.e. 100 ppbv per species using methanol impinger; or 500 ppbv per species in Tedlar® bag by GC/MS)

Table 2-3:
Comparison of DGCS Sampling Methods

Comparison of DGCS Sampling Methods	
DGCS Inlet	**Total Siloxane (ppbv)**
Tedlar® – Inlet	3,584
SUMMA Canister – Inlet	554
Methanol Impinger – Inlet	1,457

Table 2-4:
Cat Ox/SCR Performance Guarantees

Exhaust Component	Maximum Catalyst System Inlet (ppmv)	Maximum Catalyst System Outlet (ppmv)	Reduction Guarantee
NOx	50	9	82.0%
VOC	120	25	79.2%
CO	800	100	87.5%
Free Ammonia Slip	N/A	10	N/A

Notes: 1) Provided by Johnson Matthey price quotation, dated May 8, 2009.
2) N/A indicates not applicable. Ammonia was not measured before the catalyst.

Table 2-5:
Preliminary Testing Schedule

Test Run	Engine Load %	Natural Gas/Digester Gas Fuel Ratio (% NG / % DG)	Time Period (min)
1	60	50 / 50	30
2	80	50 / 50	30
3	100	50 / 50	30
4	110	50 / 50	30
5	60	100 / 0	30
6	80	100 / 0	30
7	100	100 / 0	30
8	110	100 / 0	30
9	60	5 / 95	30
10	80	5 / 95	30
11	100	5 / 95	30
12	110	5 / 95	30

Table 2-6:
Initial Pilot Study Test Program (95% Digester Gas and 5% Natural Gas)

Parameter	Reference Method	Load	No. of Tests	Sample Location
Aldehydes [(1)]	Modified CARB Method 430	Max.	2 2	Catalytic Oxidizer Inlet Stack Exhaust
Volume Flow	SCAQMD 1.1-4.1 EPA 19	Max. Normal Min.	1	Stack Exhaust
NO_x, CO, O_2 and CO_2	SCAQMD 100.1	Max. Normal Min.	1	Stack Exhaust
Ammonia	Modified SCAQMD 207.1	Max. Normal Min.	2	Stack Exhaust
VOCs (as NMNEOC)	SCAQMD 25.3	Max.	1	Catalytic Oxidizer Inlet SCR Outlet Stack Exhaust
NOx, CO, O_2	CEMS	N/A	N/A	Stack Exhaust
NOx, O_2	CEMS	N/A	N/A	Catalytic Oxidizer Inlet

Note: 1) Aldehydes analysis included formaldehyde, acetaldehyde, and acrolein.
2) N/A indicates not applicable.

Table 2-7:
Pilot Study Project Timeline

Action	Date
Project Construction Period	10/2009 – 3/2010
Commissioning	
■ Digester Gas Cleaning System Commissioning (AFT)	3/9/10
■ Cat Ox/SCR System Commissioning (Johnson Matthey)	3/22/10-3/31/10
Preliminary Testing/SCR Urea Injection Mapping (Johnson Matthey)	3/31/10 – 4/1/10
Pilot Study – Commence Testing	**4/1/10**
Source Testing using Compliance Methods (SCEC)	4/7/10 – 4/8/10
Urea Injection Mapping Adjustment #1 (Johnson Matthey)	5/13/10
Urea Injection Mapping Adjustment #2 (Johnson Matthey)	6/8/10
Completed Pilot Testing	3/31/11
Post-Pilot Study Testing	**4/1/11 – present**
Urea Injection Mapping Adjustment #3 (Johnson Matthey)	4/11/11 – 4/12/11

Figure 2-1: Plant 1 Engines 1, 2, and 3 (pictured left to right)

Figure 2-2: Schematic of the Pilot Testing System

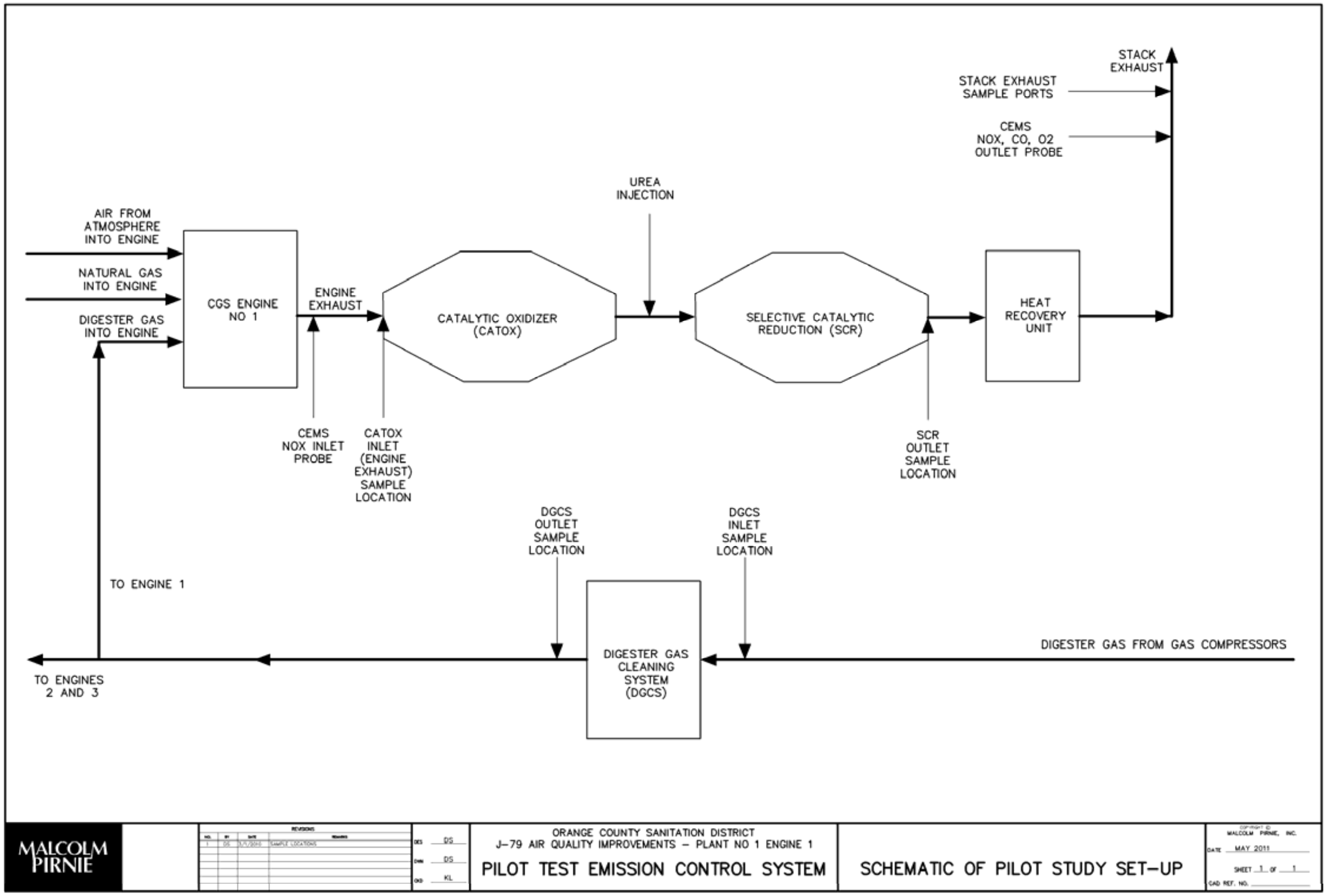


Figure 2-3: Digester Gas Cleaning System

Figure 2-4: Cat Ox/SCR Platform Installation

Figure 2-5: Catalyst and Housing

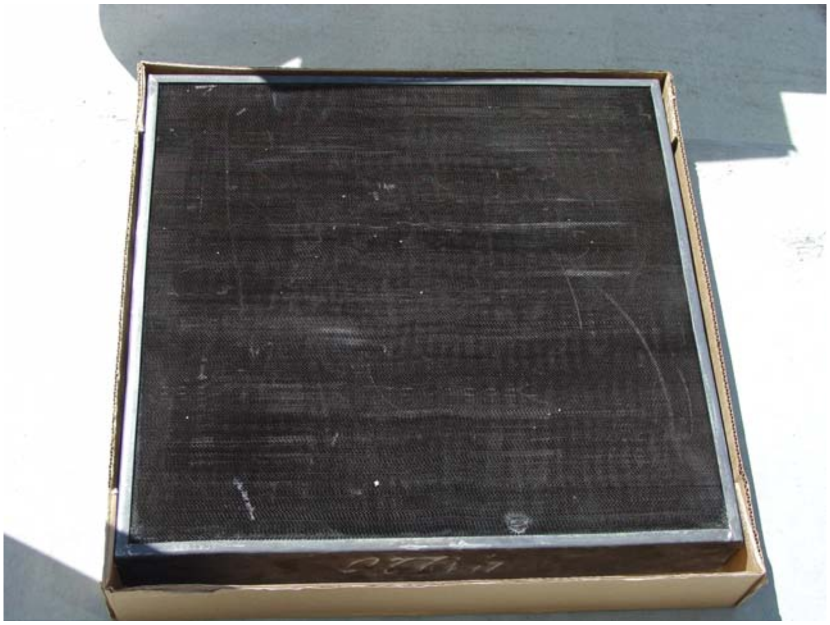
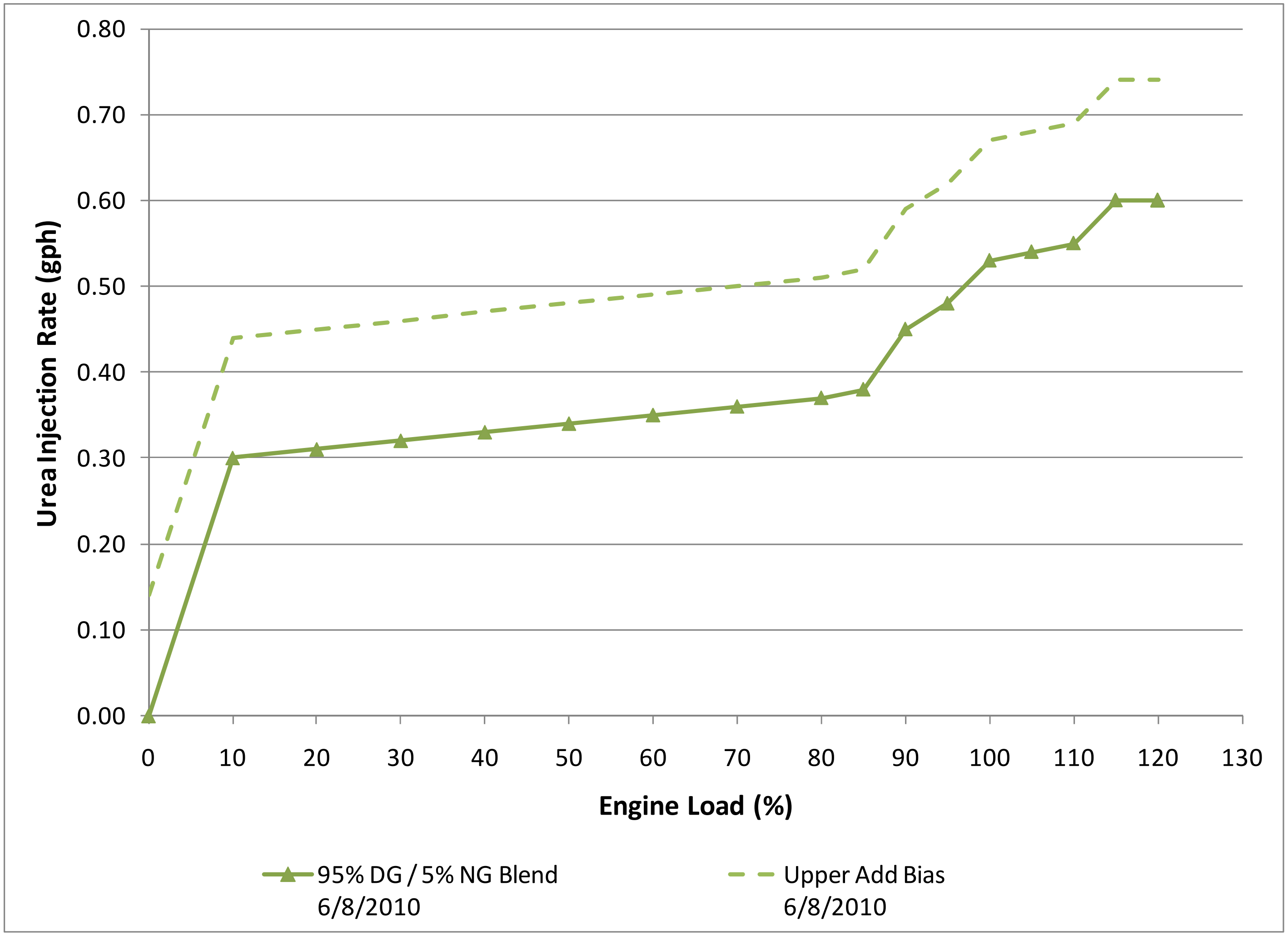


Figure 2-6: SCR Urea Injection Curve for Pilot Testing

(June 8, 2010 through March 31, 2011)



3. Results and Discussion

3.1. Digester Gas Cleaning System

The digester gas cleaning system installed at Plant 1 was designed to remove siloxanes and other impurities from the digester gas prior to being used to fuel the three IC engines. Throughout the pilot study, the performance of the DGCS system was evaluated by monitoring for carbon media performance and change out frequency. Samples for the family of siloxanes, H_2S, and speciated VOCs in the digester gas were taken at the inlet and outlet to the DGCS carbon vessel, and sent to the laboratory for testing. When the testing indicated that the DGCS media needed replacement, flow to Engine 1 was curtailed until the media was replaced. Digester gas continued to be used by Engines 2 and 3 since they were not equipped with post-combustion catalyst controls that could be fouled by the siloxanes and other contaminants in the digester gas. Once the DGCS media was replaced, the testing was resumed on Engine 1.

3.1.1. DGCS Sample Integrity

The composition of the digester gas at the inlet to the DGCS was tested for a number of compounds, including H_2S, as an indicator compound for media breakthrough, reduced sulfides, siloxanes, and a number of speciated VOCs. Since the sampling was performed using Tedlar® bags, and occasionally SUMMA canisters, the potential exists for ambient air to be captured along with the digester gas, thus diluting the sample. In order to assure that the samples were not diluted, the fixed gas composition of the gas was also measured. Fixed gases are gases for which no liquid or solid can form at the temperature of the gas, such as air at typical ambient temperatures. In the present study, N_2, O_2, CO_2, and CH_4 were the fixed gases sampled. The digester gas typically consisted of 36% carbon dioxide, 61% methane, 2% nitrogen, and less than 1% oxygen. In the event that ambient air is pulled into the digester gas sample bag, the percentage of nitrogen will be significantly greater than 2%, and the concentrations of the digester gas contaminants would be diluted.

A summary of the fixed gas composition sampling data from March 2010 through February 2011 is shown in Table 3-1. The full fixed gas composition data set is found in Appendix B-1. Over the course of this fixed gas composition sampling, three samples were eliminated due to errors in sample collection that led to a nitrogen percentage greater than 5%; one sample set (Tedlar® and Summa canister) was also eliminated due to extremely high nitrogen concentrations indicating that ambient air had leaked into the sample. However, a comparison of the inlet and outlet fixed gas composition demonstrated that the integrity of the overall digester gas samples taken was maintained with inlet and outlet concentrations of CO, CH_4, N_2, and O_2 staying within the range expected, indicating that the carbon media did not adsorb methane or the other fixed gases.

3.1.2. Digester Gas Quality

Table 3-2 presents the results of the reduced sulfides component of the digester gas. The data indicate that H_2S is the biggest constituent of the reduced sulfides sampled. The average H_2S concentration was approximately 26 ppmv. The high H_2S input concentration makes it a good indicator compound for detecting catalyst media breakthrough at the outlet of the system. Table 3-3 presents the results of the speciated siloxane sampling. Typical of digester gases in general, D5 and D4 are the largest siloxane components of the Plant 1 digester gas. Table 3-4 presents the results of the VOC sampling. The reduced sulfide, speciated siloxane, and VOC data sets are found in Appendices B-2, B-3, and B-4, respectively.

3.1.3. DGCS Performance

The DGCS was monitored for carbon media performance and change out frequency throughout the study. Digester gas samples were taken at the inlet and outlet of the DGCS carbon vessel for total siloxane concentration and H_2S, and at the inlet for speciated siloxanes, reduced sulfides, and VOCs. Samples below the method detection level (MDL) were not used in the summary analysis.

Siloxane samples were collected using Tedlar® bags and analyzed using GC/MS at both inlet and outlet of the system. Due to the length of time required to analyze the siloxane samples (approximately several days to two weeks), H_2S sampling at the DGCS outlet using Draeger tubes was used as a real-time indicator of the DGCS carbon media performance. When H_2S was detected in the DGCS outlet above approximately 1 ppmv, Engine 1 was shut-down to prevent fouling of the catalyst material until the carbon media was replaced in the DGCS. The use of 1 ppmv H_2S as an indicator for potential media saturation is a conservative threshold selected to ensure that media breakthrough would not occur during the study. Table 3-5 presents the results of the siloxane and H_2S sampling. The table indicates that the siloxane concentrations at the inlet varied over the course of the study. As shown in Table 3-3, the average inlet concentration of total siloxanes at was approximately 5.0 ppmv. The DGCS generally removed siloxanes to below the MDL.

The carbon media was replaced three times during the pilot study: in June 2010, in September 2010, and in February 2011 after treatment of approximately 147, 174, and 157 million cubic feet of digester gas, respectively. Appendix B-5 provides a summary of reduced sulfide and speciated siloxane sampling events with DGCS carbon media use and change out frequencies. This media change-out information will be used in the cost evaluation for the overall system presented in Section 4. The effectiveness of DGCS media life may be longer than experienced during the current pilot testing because the media change-outs were conservatively scheduled to protect the catalyst. For longer term operations, a design change to optimize media life could include the installation of two vessels in series. The second vessel would act as a polisher to provide catalyst protection from siloxane breakthrough while allowing the media in the primary vessel to be completely exhausted.

3.2. Cat Ox/SCR System

The purpose of the demonstration project testing program was to evaluate the effectiveness of the Cat Ox/SCR system for removal of CO, VOC, and NOx to comply with amended Rule 1110.2, to monitor for ammonia slip, and to evaluate the performance of the engine with the emissions control equipment installed. The pilot testing of the Cat Ox/SCR system began on April 1, 2010, immediately after completion of the SCR urea injection mapping by Johnson Matthey. The pilot study continued until March 31, 2011.

The concentrations of CO, NOx, and O_2 in the engine exhaust gas before and after the Cat Ox/SCR system were determined by an independent source testing firm using SCAQMD Method 100.1, a chemiluminescent compliance testing method, during source testing on April 7 and 8, 2010. Routine monitoring of CO, NOx, and O_2 concentrations using OCSD's TESTO 350 XL portable handheld analyzer was also performed. The use of the portable analyzer measuring CO and NOx allowed for numerous data sets to be collected at regular intervals throughout the pilot study. The detailed portable analyzer test report can be found in Appendix C-1. In addition, a CEMS monitored and recorded the 15-minute block average NOx concentrations at the catalytic oxidizer inlet (engine exhaust) and the NOx, CO and O_2 concentrations at the stack exhaust. VOC concentrations were measured periodically at the engine exhaust and stack exhaust using SCAQMD Method 25.3.

The results of the source testing at Plant 1 using SCAQMD compliance methods on April 7-8, 2010 and SCAQMD Rule 1110.2 compliance testing in January 2011 are shown in Tables 3-6 and 3-7, respectively. Results for the January 2011 source testing at Plant 1 in Table 3-7 are also shown for Engines 2 and 3 for comparison. As shown in the January 2011 annual compliance test results (Table 3-7), the average NOx and CO concentrations in Plant 1 Engine 1 over three loads are 6.2 and 7.9 ppmv, respectively. This is lower than the average Engines 2 and 3 NOx and CO concentrations over three loads of 30.2 and 390.5, respectively. Results of the routine pilot test sampling events are provided in Section 3.3.

3.3. Compliance with Future Rule 1110.2 Emission Limits

The results of the pilot study were evaluated for compliance with the future Rule 1110.2 emission limits. The CO and VOC results represent data collected after the initial startup of the equipment from April 1, 2010 through March 31, 2011. The NOx results represent data collected after the urea injection system was optimized on June 8, 2010 through March 31, 2011.

3.3.1. Carbon Monoxide Concentration

CO concentration data were collected during source testing at the engine exhaust and stack exhaust routinely throughout the pilot testing period using the hand-held portable analyzer at the engine exhaust and SCR outlet and also continuously at the stack exhaust by the CEMS. The data collected during these events is summarized in Table 3-8. All CO data collected by the portable analyzer and the CEMS are presented in Appendices C-1 and C-3, respectively.

The CO concentration data at the engine exhaust (CO inlet) and the stack exhaust (CO outlet) are presented graphically in Figure 3-1. The CO inlet concentration was measured with the portable analyzer. The CO outlet concentration, measured by the CEMS, is shown as the maximum daily 15-minute average CO outlet concentration. The percent reduction in CO concentration measured across the Cat Ox/SCR system by the portable analyzer consistently exceeded 96% reduction. This performance was consistent when firing either digester or natural gas. This CO concentration removal rate exceeds the expected performance based upon the catalytic oxidizer vendor guarantee of 87.5% CO removal, provided in Table 2-4.

3.3.2. Volatile Organic Compounds Concentration

The VOC concentration data in terms of NMNEOC was collected during source testing at the engine exhaust, the stack exhaust, and routinely throughout the pilot testing period using SCAQMD Method 25.3. All data collected is presented in Appendix C-2. As shown in Table 3-9, the average VOC concentration at the stack exhaust was 3.58 ppmv, below the emission limit of 30 ppmv in the future Rule 1110.2.

Data measured during the pilot testing period were compared to VOC concentrations measured for the OCSD Rule 1110.2 Annual Permit Compliance Test Report for Year 2011. Table 3-7 summarizes the annual permit compliance VOC test results for OCSD Plant No. 1.

The average uncontrolled VOC concentration for Engines 2 and 3 during the compliance testing was 97 ppmv, while the controlled VOC concentration from Engine 1 stack exhaust was 3.24 ppmv. This is in the same range of the VOC concentrations measured during the pilot testing period (i.e., 3.58 ppmv), confirming the effectiveness of the catalytic oxidizer (at approximately 96%) in removing VOCs from the engine exhaust.

It should be noted that the stack exhaust VOC concentrations for Engines 2 and 3 of 97.2 and 96.9 ppmv, respectively, are much higher than the VOC concentrations measured at the Engine 1 engine exhaust during the pilot testing period, which averaged 21.84 ppmv (refer to Appendix C-2). One possible explanation to this is the arrangement of the Engine 1 sampling port before the catalytic oxidizer. Typically, when sampling using SCAQMD Method 25.3, two samples are gathered from two separate probes and the results of the analyses are averaged. In the case of this pilot study, the valve at the engine exhaust sampling port was not large enough to locate two adjacent probes, and it was not possible to expand the sampling port. Therefore, the sample and duplicate sample were not taken at the same time, but one after the other. The VOC data collected at the engine exhaust represents the higher of the two sample data results, in line with SCAQMD's general mandate that the higher value be reported when the results differ by more than 20%. Despite the lower accuracy in the engine exhaust sample due to the sizing of the sampling port, the sample taken at the stack exhaust location met the SCAQMD accuracy criteria.

3.3.3. Nitrogen Oxides Concentration

NOx concentration data were collected during source testing at the engine exhaust and stack exhaust, routinely throughout the pilot testing period using the portable hand-held analyzer at the engine exhaust, after the catalytic oxidizer and stack exhaust; and continuously at the engine exhaust and stack exhaust by the CEMS.

Based on the results of previous source testing, it is observed that the concentration of NOx produced in the engine exhaust for a given load is higher when firing natural gas than when firing digester gas at any given load. Therefore, the efficiency of the SCR system is reduced as the percentage of natural gas increases. The original urea injection set points, set on April 1, 2010 during commissioning, were set for a blend of digester gas and natural gas. The set points, which are a function of engine load, were adjusted on June 8, 2010 to decrease urea flow because a higher ratio of digester gas to natural gas was fired in Engine 1 than was originally anticipated. Therefore, the urea injection rates were reduced to control a lesser concentration of NOx in the exhaust gas. The data presented in this section represents the pilot testing period from June 8, 2010 through March 31, 2011. The data collected during this period are summarized in Table 3-10. The entire dataset collected is presented in Appendix C-3.

The NOx concentration data at the engine exhaust and the stack exhaust measured by the CEMS are presented graphically in Figure 3-2. The NOx inlet and outlet concentration is shown as the daily maximum 15-minute average NOx concentration. The percentage reduction in NOx concentration measured across the Cat Ox/SCR system by the portable analyzer ranged from 76 to 98%. This NOx concentration removal rate is close to the expected performance based upon the Cat Ox/SCR vendor guarantee of 82% NOx removal. A review of the NOx concentration data over the period of the pilot study indicates that the performance of the SCR is affected both by the ratio of digester to natural gas used as fuel in the engine, and by the system's responsiveness to engine operating parameters, such as start-up and differing load conditions. The inability of the

SCR system to meet the vendor guarantee may be due to periods of increased natural gas flow in the fuel gas. This was to be expected because the urea injection system was mapped for a primarily digester gas (greater than 95 percent) fuel blend. The control system can only be set with one set of engine load to urea injection set points and is not designed to change urea injection rates depending on the fuel blend. Johnson Matthey has not designed a control system that can accommodate varying loads and fuel blends. Therefore, during periods when the fuel is supplemented by natural gas, the NOx removal efficiency is expected to be reduced. If the set points were adjusted for a natural gas fuel usage, which is atypical, the system may over-inject urea potentially causing an ammonia slip as discussed below.

3.3.3.1. NOx Concentrations Above Rule 1110.2 Limit

During the pilot testing period, the NOx outlet concentration occasionally spiked above the future Rule 1110.2 limit of 11 ppmv. NOx concentrations are measured continuously by the CEMS system and averaged in 15-minute blocks for compliance purposes. For the purposes of this Report, each 15-minute block is defined as a "period". A "high NOx outlet event" is defined as one period or multiple periods in a short time span where the NOx outlet concentration exceeds 11 ppmv. The NOx outlet concentration exceeded 11 ppmv for a total of 97 high NOx outlet events (940 periods out of 21,285 periods of engine operating time) during the pilot test.

Many of the high NOx outlet events were removed from the data set when evaluating performance of the SCR system. A majority of the spikes in NOx outlet concentration correlated with high NOx outlet events when: 1) the engine had just come online, 2) there was an increase in the percentage of natural gas in the engine fuel blend, 3) engine loads exceeded the loads mapped during the initial urea injection rate programming, and 4) operational adjustments of the Cat Ox/SCR system took place. Once excursions over 11 ppmv were screened for exempt or non-valid conditions such as engine start-up and non-control system error, 181 15-minute periods out of 21,285 periods of operating time (less than 0.9% of the total measurement periods during the pilot study) remained above 11 ppmv. The lowest NOx stack exhaust concentration met consistently under all valid conditions was 16 ppmv. Table 3-11 presents a break-down of the number of high NOx outlet events and periods when the NOx outlet concentration at the stack exhaust exceeded 11 ppmv.

Exempt or Non-Valid Periods. A total of 7 high NOx outlet events (703 periods or 3.3% of the total engine operating period) were during times when operational issues and system adjustments caused the NOx to exceed 11 ppmv. These events included urea injection system adjustments by the system vendor, operation of the SCR system without urea in the storage tank, modifications to the engine automation system, improper operation of the SCR system, and clogging in the urea injection lance. These periods were removed from the stack exhaust NOx data set because they do not represent proper operating conditions of the SCR system.

During the pilot testing period, 29 high NOx outlet events (56 periods or 0.3% of the total engine operating time) were classified as occurring during engine start-up. Rule 1110.2(h)(10) allows for an exemption during engine start-up to allow for sufficient operating temperatures to be reached for proper operation of the emission control equipment. The start-up period is limited to 30 minutes unless a longer period is approved for a specific engine by the Executive Officer and is made a condition of the engine permit. Periods where NOx outlet concentrations exceeded 11 ppmv within 30 minutes of engine start-up were removed from the data set for evaluation of the SCR system performance.

Validated Periods. A number of the remaining high NOx outlet events could be attributed to periods during which the engine was operating with natural gas fuel or at a load that exceeded the range that was originally mapped into the urea injection system. The urea injection system was programmed assuming a fuel blend of 95% digester gas to 5% natural gas. An event was attributed to a rise in natural gas usage if the fuel blend decreased to below 95% digester gas during the same period or during the period immediately preceding the event. A total of 17 high NOx outlet events (43 periods or 0.2% of total engine operating time) occurred when the fuel blend decreased to below 95% digester gas. It was observed that the production of NOx at the engine exhaust increased as the percentage of natural gas in the engine fuel increased. Therefore, as the digester gas to natural gas fuel ratio decreased to below 95% digester gas (i.e., using more natural gas in the fuel blend), the urea injection system would not inject a sufficient quantity of urea to compensate for the additional NOx being produced and NOx outlet concentration would increase.

A total of 22 high NOx outlet events (63 periods or 0.3% of the total engine operating time) occurred when the engine load exceeded 100%. During the pilot testing period, the urea injection rate setpoints were set for an engine load range of 0% to 100%. An event was considered to be due to an increase in engine load if the engine load increased to above 100% during the same period or during the period immediately preceding the event. When the engine load exceeded 100% of design load for an extended period of time, the urea injection rate was not able to adjust properly because the engine operation surpassed the programming of the system.

There are 22 high NOx outlet events (75 periods or 0.4% of the total engine operating time) that could not be attributed to operational issues/system adjustments, engine start-up, increased natural gas fuel usage, or high engine load. The NOx outlet concentrations during the majority of these periods typically ranged between 11 and 12 ppmv, with a maximum of 16 ppmv.

The maximum NOx concentration at the outlet was 16 ppmv after removing the non-control system related exceedances, including operational issues/system adjustments and engine start-up. The validated average, minimum, and maximum NOx outlet concentrations recorded by the CEMS are presented in Table 3-12. The validated data set includes the NOx outlet concentration data during increased natural gas fuel usage, high engine load, and other high NOx outlet events not attributed to operational issues/system adjustments, engine start-up, increased natural gas fuel usage, or high engine load. Following the pilot test, the urea injection setpoints and biases may be increased to account for increased NOx production due to increased natural gas in the fuel blend and higher engine loads. Increasing the urea injection setpoints may also reduce the number of other high NOx outlet events that fall just above the 11 ppmv NOx limit.

In April 2011, after the official pilot testing period concluded, a Johnson Matthey technician adjusted the urea injection rate curve to 1) expand the curve to a maximum of 125% engine load and 2) to increase the urea injection rate at high engine loads. The increase in urea injection rate should accommodate for the increased NOx production when the engine incorporates more natural gas into the fuel blend. Further observation will be required to confirm if these adjustments will lead to a reduction in the number of periods where stack exhaust NOx outlet concentration exceeds 11 ppmv.

3.3.4. Ammonia Concentration

The SCR system reduces NOx through a chemical reaction between ammonia and NOx, facilitated by a catalyst to form nitrogen and water vapor. Once urea is injected into the engine exhaust stream, it breaks down into ammonia and other constituents. Hydrolysis of the urea on the face of the catalyst generates more ammonia. While NOx reduction is the goal of the SCR system through the consumption of the ammonia, injection of too much urea can result in excess ammonia (total ammonia) at the SCR outlet in the form of free ammonia (NH_3), and/or other ammonia-formed compounds. Parts of the total ammonia can then participate in secondary reactions with other compounds in the exhaust gas forming by-products, such as ammonium sulfates (combined ammonia). These secondary ammonia by-products may have the undesirable potential to increase maintenance requirements on the equipment downstream from the SCR, due to clogging and particulate buildup. The remaining gaseous ammonia (free ammonia) that is emitted at the stack exhaust is referred to as ammonia slip. SCAQMD regulated the amount of ammonia slip in the Pilot Study Research Permit not to exceed 10 ppmv of free ammonia at the stack exhaust.

Three methods were used for determining ammonia concentration:

- On-site field measurement of free ammonia using Draeger® or Sensidyne® tubes,
- Modified SCAQMD Method 207.1 to measure free ammonia, and

- Estimated total ammonia concentration (free plus combined ammonia) calculation method using inlet and outlet NOx CEMS concentrations and the urea injection rate.

Free ammonia concentration data was collected during source testing at the stack exhaust using modified SCAQMD Method 207.1, and also routinely monitored throughout the pilot testing period using Draeger® tubes or Sensidyne® tubes at the SCR outlet. Both tests provide concentration data for free ammonia. Total ammonia was also calculated from the CEMS data based on the NOx inlet and outlet concentrations and the urea injection rate. The limitations of this total ammonia calculation are discussed in detail in a technical memorandum *OCSD Cat Ox/SCR Pilot Study: Ammonia Sampling and Calculation Methods* (Malcolm Pirnie, May 2011) found in Appendix C-2. As with the NOx data, the ammonia data presented in this section represents data collected during the pilot testing in the period from June 8, 2010 through March 31, 2011, after the urea injection rate set points were adjusted on June 8, 2010. Figure 3-3 presents the maximum total ammonia estimate for each day of the pilot test between these dates using the calculation method.

Over the course of the pilot testing period, the Draeger® tubes consistently measured free ammonia concentrations at the stack exhaust below MDL. During the same time period when the ammonia field measurements were taken, the calculated total ammonia concentration using the 15-minute block averages reported by the CEMS had a value ranging from 0 to 5 ppm of ammonia.

Estimated Total Ammonia Calculation. The calculation method for total ammonia is dependent on the NOx inlet and NOx outlet concentrations and the urea injection rate, which is continuously adjusting based on the engine load and the NOx outlet concentration. The ammonia calculation equation is shown below, where CF can be used as a correction factor to account for factors such as secondary reactions and limitations of the urea injection system, and as a tool to adjust the calculation of total ammonia to estimate free ammonia.

$$NH_3 = [\text{Urea Fed} - (\text{NOx in} - \text{NOx out})/2] \times CF$$

The CF was assumed to be equal to 1 in the present study. Throughout the pilot testing, differences were observed between the free ammonia measured in the field and total ammonia estimated using the calculation method. The calculation method assumes that the ammonia/NOx reaction is the only reaction consuming the urea. There is the potential for ammonia molecules to be consumed in other secondary reactions in the exhaust stream, such as those with sulfur compounds. Sulfur dioxide (SO_2) and sulfur trioxide (SO_3) can react with ammonia to produce ammonium sulfate (NH_4HSO_4) and ammonia bisulfate (ammonia hydrogen sulfate) ($(NH_4)_2SO_4$) which can precipitate out of the exhaust gas at low temperatures (300-450°F) as ammonium salts (combined ammonia). Ammonium salts have the potential to deposit on equipment downstream from the SCR catalyst, such as the heat recovery boiler, reducing their efficiency and increasing maintenance requirements. Field measurements during the pilot test were only performed for free ammonia which did not include ammonia compounds, such as the ammonium salts. Low ammonia concentration Draeger® tube measurements combined with the and high exhaust gas temperatures (~ 800°F) taken directly after the SCR catalyst indicate that the potential for these secondary reactions is low.

Engine load fluctuates with time. When the IC engines are set to a base load, it was observed that the actual engine load fluctuated rapidly by as much as ten percent below the set point. This was found to be typical for the OCSD IC engines. However, since urea injection rate is mapped to engine load, the rapid fluctuations in load can result in rapid changes in urea injection rates. Rapidly changing urea injection rates, instead of steady rates with smooth transitions, can cause inaccuracies in the ammonia calculation.

SCAQMD Sampling Using Compliance Methods. Free ammonia was measured at the stack exhaust once during the initial source testing event from April 7-8, 2010, and once after the pilot testing period on May 10, 2011. On both occasions, ammonia slip concentrations at three engine loads measured by Modified SCAQMD Method 207.1 were found to be less than 0.5 ppmv. Neither the Draeger® tube nor Sensidyne® tube free ammonia measurements at the SCR exhaust were above the MDL. However, the total ammonia estimate based on the theoretical calculation using the CEMS data was three to ten times higher than the measured value using the compliance method. Results of these sampling events are compared in Table 3-13.

Further sampling of the exhaust emissions can be performed to establish a value for the correction factor, CF, in the estimated total ammonia calculation method for the calculation of free ammonia. If found, the presence of sulfur dioxide and sulfur trioxide in the exhaust gas before the SCR, and ammonium sulfate and ammonia bisulfate, in the exhaust gas after the SCR, can indicate secondary reactions taking place due to the injection of urea. In addition, inspection of the heat recovery boiler during the next scheduled maintenance may also indicate the presence of ammonium salts in the exhaust gas. A correction factor can be applied to the estimated total ammonia calculation to account for these secondary reactions, thus allowing for the estimation of free ammonia. If ammonium salts are identified in the heat recovery boiler, adjustments to the urea injection rates or additional maintenance of the heat recovery boiler may be required.

Compliance monitoring for free ammonia is more accurate when reflective of gaseous ammonia emitted from the stack, while the estimated total ammonia calculation method may reflect both free ammonia and ammonia by-products produced in the exhaust gas. Although the pilot study data indicates that there is minimal, if any, free ammonia (ammonia slip) due to the SCR system, it is recommended that the OCSD perform additional and routine testing for ammonia slip during varying loads and fuel blends over a period of time.

3.4. Engine Performance

A significant amount of operational data was collected throughout the pilot test. The data logger installed within the urea injection control cabinet collected additional data beyond that collected by the CEMS. These data included the temperature at the catalytic oxidizer inlet and outlet, and the SCR inlet and outlet and the differential pressure across the catalytic oxidizer and SCR catalysts. The system urea injection and back pressure performance proposed by Johnson Matthey is provided in Table 3-14. The data collected by the data logger are summarized in Table 3-15 and were validated to remove periods when the engine was offline. Periods when the engine was offline were identified as those periods when the urea injection is offline, when the temperatures in the catalyst housings cool and the NOx inlet concentration decreases to zero.

During the pilot test, there were no notable back pressure effects on engine performance due to the installation of the Cat Ox/SCR system with a digester gas cleaning system. The engine manufacturer's allowable back pressure is 20 inches of water column (in. wc.). The engineering design estimate of the maximum engine exhaust system back pressure without the Cat Ox/SCR system was 11 in. wc. Therefore, the available system design back pressure for the Cat Ox/SCR system and additional exhaust ductwork was 9 in. wc. Based on the data provided by the data logger in during the pilot test, the average differential pressure through the catalytic oxidizer and SCR are approximately 0.3 and 1.0 in. wc., respectively. Therefore, it is concluded that the system does not negatively affect engine performance.

The exhaust gas temperature reported through the catalytic oxidizer and SCR and the urea injection rate indicate proper system performance. The average inlet and outlet temperature through both catalysts is between 750°F and 800°F, which is in the proper temperature range for ammonia to react in the SCR catalyst. The actual urea injection rate of approximately 0.6 gallons per hour (gph) is also below the urea usage estimate of 1.1 gph proposed by Johnson Matthey.

The DGCS has had a positive effect on engine performance. The use of cleaned digester gas at Plant 2 Engine 3 resulted in much less frequent maintenance requirements for the engine, including longer time intervals between spark plug changes and major maintenance events. OCSD Operations continues to use the DGCS from the 2007 pilot study at Plant 2 Engine 3 after improvements in performance of the engine and maintenance cost savings resulted from use of the DGCS. These savings are discussed further in Section 4.

3.5. Summary of System Results

The overall results of the pilot study are:

- The maximum NOx concentration at the stack exhaust after the pilot study controls was approximated 16 ppmv, and the average NOx concentration was approximately 7.2 ppmv, below the 11 ppmv required under amended Rule 1110.2. Further adjustment of the urea injection rate was performed after the end of the pilot study, and these new data will be evaluated further to determine if this urea injection rate modification will eliminate excursions above 11 ppmv.
- While there were some excursions above 11 ppmv, once these excursions were screened for exempt conditions like start-up, and non-control system error, less than 0.9% of the total measurement periods during the pilot study, or 181 15-minute periods out of 21,285 periods in total remained above 11 ppmv.
- Using monitoring data for gaseous free ammonia collected using the SCAQMD method and Draeger® tube method, the free ammonia concentration was below 0.5 ppmv and MDL over the pilot study, respectively.
- Based on the calculation method for total ammonia, the maximum total ammonia concentration during ammonia concentration sampling events was estimated to be 4.65 ppmv. It is believed that this is an overestimate due to limitations of the calculation, such as not accounting for potential secondary ammonia reactions. Despite this, the estimated total ammonia calculation method can be used as a tool to prompt a field measurement to determine free ammonia (ammonia slip) with the application of an appropriate correction factor, CF. Further evaluation needs to be performed to develop a correction factor that will correlate the calculation method and the measured values of free ammonia.
- The percentage reduction in CO concentration measured across the Cat Ox/SCR system by the portable analyzer ranges consistently exceeded a 96% reduction in CO concentration from the engine exhaust.
- The maximum CO concentration at the stack exhaust using the CEMS data was 42.2 ppmv, well below the amended Rule 1110.2 emission limit of 250 ppmv.
- The catalytic oxidizer was found to result in removing approximately 96 % VOCs from the engine exhaust.
- The maximum VOC concentration at the stack exhaust was found to be 5.42 ppmv using Method 25.3, and consistently well below the 30 ppmv in amended Rule 1110.2.

- The DGCS system, in general, removed siloxanes from the digester gas to below MDL levels and significantly reduced sulfur compounds and VOCs successfully reducing catalyst masking which should lead to extended catalyst life.
- The DGCS system resulted in overall improvements in engine maintenance requirements.
- No back pressure concerns for the engine due to the additional equipment were identified.

Table 3-1:
Summary of Fixed Gases in Plant 1 Digester Gas

Fixed Gas	DGCS Inlet			DGCS Outlet		
	Min.	Max.	Avg.	Min.	Max.	Avg.
	(%)	(%)	(%)	(%)	(%)	(%)
Carbon Dioxide (CO_2)	25.5	40.1	33.9	23.1	37.2	32.8
Methane (CH_4)	53.7	62.6	58.7	45.0	62.5	58.0
Nitrogen (N_2)	0.9	5.1	2.2	1.1	1.9	1.5
Oxygen (O_2)	0.1	1.4	0.6	0.1	0.8	0.4

Table 3-2:
Summary of Reduced Sulfides in Plant 1 Digester Gas

Compound	DGCS Inlet		
	Min. (ppmv)	Max. (ppmv)	Avg. (ppmv)
Hydrogen Sulfide	14.7	31.9	26.4
Carbonyl Sulfide	0.01	0.03	0.02
Methyl Mercaptan	0.05	0.08	0.06
Ethyl Mercaptan	0.2	0.3	0.3
Dimethyl Sulfide	0.006	0.02	0.01
Carbon Disulfide	0.004	0.009	0.006
n-Propyl Thiol	0.5	0.8	0.6
iso-Propyl Thiol	0.2	0.4	0.3
Dimethyl Disulfide	ND	ND	ND
Isopropyl Mercaptan	0.3	0.3	0.3
n-Propyl Mercaptan	0.3	0.3	0.3

Note: 1) ND indicates non-detect.

Table 3-3:
Summary of Speciated Siloxanes in Plant 1 Digester Gas

Compound	DGCS Inlet		
	Min. (ppbv)	Max. (ppbv)	Avg. (ppbv)
Hexamethyldisiloxane (L2)	<MDL	<MDL	<MDL
Hexamethylcyclotrisiloxane (D3)	10	17	12
Octamethyltrisiloxane (L3)	10	19	14
Octamethylcyclotetrasiloxane (D4)	369	1,600	704
Decamethyltetrasiloxane (L4)	73	170	121
Decamethylcyclopentasiloxane (D5)	1,300	14,000	5,371
Total Siloxanes	919	15,700	5,452

Note: MDL is mean detection level.

Table 3-4:
Summary of Speciated VOCs in Plant 1 Digester Gas

Analyte	DGCS Inlet		
	Min. (ppbv)	Max. (ppbv)	Avg. (ppbv)
Acetone	7.0	88.0	26.0
Benzene	7.3	15.7	10.7
Chlorobenzene	4.5	6.4	5.4
Cyclohexane	4.9	22.0	13.6
1,4-Dichlorobenzene	5.0	28.0	16.4
cis-1,2-Dichloroethene	17.2	103.0	41.4
trans-1,2-Dichloroethene	4.6	4.6	4.6
Ethyl Acetate	22.2	22.2	22.2
Ethylbenzene	37.0	141.0	74.2
4-Ethyltoluene	12.7	68.6	33.7
Freon 11	5.2	6.3	5.8
n-Heptane	57.8	122.0	84.2
Hexane	27.0	210.0	76.5
Methylene Chloride	5.2	14.0	8.9
Methyl Isobutyl Ketone (MIBK)	4.4	4.5	4.4
Propene	2,410	3,730	3,226
Styrene	4.2	24.7	10.7
Tetrachloroethene (PCE)	11.0	11.0	11.0
Tetrachloroethylene	6.0	26.3	13.5
Toluene	1,090	7,300	2,296
1,2,4-Trichlorobenzene	9.2	9.2	9.2
Trichloroethene (TCE)	9.6	28.0	15.8
Trichloroethylene	6.2	22.9	11.7
1,2,4-Trimethylbenzene	67.1	240.0	123.1
1,3,5-Trimethylbenzene	30.0	88.0	45.8
2,2,4-Trimethylpentane	27.0	66.0	52.0
m & p-Xylene	47.0	180.0	96.1
o-Xylene	20.0	64.0	36.3
Total VOCs	**1,594**	**11,133**	**4,927**

Table 3-5:
Summary of Siloxane and H_2S Sampling

Date of Sampling	Approximate Volume of Gas Treated (million cubic feet)	Total Siloxane		H_2S			
				SCAQMD 307-91		Draeger Tube	
		Inlet (ppmv)	Outlet (ppmv)	Inlet (ppmv)	Outlet (ppmv)	Inlet (ppmv)	Outlet (ppmv)
3/16/2010	0.00	3.58	<MDL	N/A	N/A	N/A	N/A
4/7/2010	27.26	8.51	<MDL	N/A	N/A	N/A	N/A
4/21/2010	53.41	N/A	N/A	25.70	ND	26	ND
4/29/2010	68.93	15.70	ND	N/A	N/A	N/A	N/A
5/11/2010	91.86	N/A	N/A	31.70	0.263	31	ND
5/27/2010	122.58	2.67	0.015	N/A	N/A	N/A	N/A
6/8/2010	144.70	N/A	N/A	27.97	2.162	30	2
6/11/2010	146.46	8.49	0.248	N/A	N/A	N/A	N/A
6/12/2010	Carbon media changed.						
6/22/2010	18.44	N/A	N/A	21.62	ND	27	N/A
6/29/2010	32.70	8.69	N/A	N/A	N/A	N/A	N/A
7/7/2010	46.34	N/A	N/A	28.57	ND	25	N/A
7/21/2010	68.89	N/A	N/A	24.87	ND	25	N/A
8/3/2010	90.04	N/A	N/A	27.45	ND	25	N/A
8/12/2010	106.00	N/A	N/A	28.19	ND	26	N/A
8/12/2010	106.00	3.73	ND	N/A	N/A	N/A	N/A
9/1/2010	137.15	4.57	<MDL	N/A	N/A	N/A	N/A
9/1/2010	137.15	N/A	N/A	14.69	ND	14	N/A
9/14/2010	162.45	N/A	N/A	23.01	0.545	23	N/A
9/15/2010	164.63	4.35	<MDL	N/A	N/A	N/A	N/A
9/17/2010	168.63	N/A	N/A	N/A	N/A	N/A	2.5
9/20/2010	173.62	5.73	<MDL	N/A	N/A	N/A	N/A
9/21/2010	Carbon media changed.						
11/4/2010	43.40	5.23	N/A	N/A	N/A	N/A	N/A
1/12/2011	114.53	6.55	N/A	N/A	N/A	N/A	N/A
1/25/2011	137.78	N/A	N/A	28.54	ND	27	N/A
2/9/2011	156.47	N/A	N/A	31.87	1.755	30	N/A
2/9/2011	156.47	4.58	<MDL	N/A	N/A	N/A	N/A
2/14/2011	Carbon media changed.						
2/23/2011	17.72	N/A	N/A	24.46	ND	25	N/A
2/24/2011	20.09	6.64	N/A	N/A	N/A	N/A	N/A

Notes: 1) All samples are taken using Tedlar® bags, except where otherwise noted as using Draeger® tubes for H_2S.
2) Inlet and outlet sample results from 5/19/10 are not accurate due to an error in collection, indicated by high nitrogen composition (>5%), and are not included in the minimum, maximum and average.

3) Outlet sample results from 6/29/10 are not accurate due to an error in collection, indicated by high nitrogen composition (>5%), and are not included in the minimum, maximum and average.
4) Inlet and outlet sample results from AccuLabs on 8/12/10 are not accurate due to an error in collection, indicated by high nitrogen composition (>5%), and are not included in the minimum, maximum and average.
5) Sample results from 8/19/10 are not consistent with sample results from other laboratories and are concluded to be erroneous and not included in the minimum, maximum and average.
6) N/A indicates that the compound was not analyzed.
7) ND indicates non-detect.
8) <MDL indicates less than the Method Detection Limit.

Table 3-6:
Plant 1 Engine 1 April 7-8, 2010 Testing using SCAQMD Compliance Methods

Parameter	Units	Low Load	Normal Load	High Load	Average Load
Load	KW	1,598	2,303.5	2,515.8	2,139.1
	%	65	90	105	86.7
Volume Flow	dscfm	5,662	8,423	9,244	7,776.3
Fuel Flow	NG scfm	14.2	19.7	20.8	18.2
	DG scfm	470.7	635.3	688.8	598.3
Stack Exhaust					
NOx	ppm	6.5	4.7	8.5	6.6
CO	ppm	7.3	4.9	4.9	5.7
TGNMNEO	ppm	N/A	N/A	2.6	2.6
Formaldehyde	ppm	N/A	N/A	0.434	N/A
Acetaldehyde	ppm	N/A	N/A	0.023	N/A
Acrolein	ppm	N/A	N/A	< MDL	N/A
Ammonia	ppm	0.12	0.18	0.43	0.2
O_2	%	10.59	11.97	12.03	11.5
CO_2	%	8.56	7.55	7.69	7.9
Engine Exhaust					
TGNMNEO	ppm	N/A	N/A	25.86	N/A
Formaldehyde	ppm	N/A	N/A	21.44	N/A
Acetaldehyde	ppm	N/A	N/A	0.419	N/A
Acrolein	ppm	0.18	0.18	< MDL	N/A

Notes: 1) N/A indicates not applicable.

2) <MDL indicates less than the Method Detection Limit.

Table 3-7:
SCAQMD Rule 1110.2 Year 2011 Permit Compliance Test Report

Parameter	Units	Low Load	Normal Load	High Load	Average Load
Engine 1					
Load	KW	1,655	1,929	2,438	2,183.5
	%	66	77	98	87.3
Volume Flow	dscfm	6,194	7,406	9,124	8,265.0
NOx	ppm	4.6	5.4	6.9	6.2
CO	ppm	6.2	7.6	8.2	7.9
TGNMNEO	ppm	N/A	3.2	N/A	N/A
PM	gr/dscf	N/A	0.0	N/A	N/A
O_2	%	10.90	11.84	12.16	12.00
CO_2	%	8.59	7.83	7.52	7.68
Engine 2					
Load	KW	1,618	1,852	2,455	2,153.7
	%	65	74	98	86.2
Volume Flow	dscfm	6,513	7,598	9,867	8,732.5
NOx	ppm	27.8	27.6	31.6	29.6
CO	ppm	348.7	390.4	432.3	411.4
TGNMNEO	ppm	N/A	97.2	N/A	N/A
PM	gr/dscf	N/A	0.0010	N/A	N/A
O_2	%	11.79	12.04	12.53	12.29
CO_2	%	7.80	7.60	7.16	7.38
Engine 3					
Load	KW	1,748	1,981	2,488	2,234.6
	%	70	79	100	89.4
Volume Flow	dscfm	6,703	7,746	9,652	8,699.0
NOx	ppm	29.1	30.1	31.2	30.7
CO	ppm	317.3	343.8	394.7	369.3
TGNMNEO	ppm	N/A	96.9	N/A	N/A
PM	gr/dscf	N/A	0.0049	N/A	N/A
O_2	%	11.68	12.01	12.49	12.25
CO_2	%	7.87	7.57	7.18	

Notes: 1) N/A indicates not applicable

Table 3-8:
Summary of CO Concentrations from Inlet and Outlet of Cat Ox/SCR System

Sampling Method	Catalytic Oxidizer Inlet Concentration (ppmvd)[1]			SCR Outlet/Stack Exhaust Concentration (ppmvd)[1]		
	Min.	**Max.**	**Avg.**	**Min.**	**Max.**	**Avg.**
Portable Analyzer[2]	367.5	598.7	451.6	<MDL	17.2	5.8
CEMS[3]	N/A[4]	N/A[4]	N/A[4]	4.0	42.2	7.5

Notes:
1) Concentrations are presented in parts per million by volume dry (ppmvd) at 15% O_2
2) CO concentrations by portable analyzer are measured routinely starting on April 7, 2010, after initial mapping of the SCR system.
3) NOx and CO CEMS data is based on an average of the 15-minute average NOx and CO concentrations for each calendar day. .
4) N/A: CEMS measures CO at the stack exhaust only; therefore, there is no CEMS data at the Cat Ox inlet.

Table 3-9:
VOC Concentrations at Stack Exhaust

Date	Stack Exhaust (ppmv)
4/7/2010	2.60
5/11/2010	0.73
8/12/2010	5.42
11/4/2010	4.21
2/24/2011	4.95
Average	3.58

Notes: All concentrations are adjusted to 15% O_2.

Table 3-10:
Summary of NOx Concentrations[1] at Inlet and Outlet of Cat Ox/SCR System

Sampling Method	Catalytic Oxidizer Inlet Concentration (ppmvd)			Catalytic Oxidizer Outlet Concentration (ppmvd)			SCR Outlet/Stack Exhaust Concentration (ppmvd)			NOx Reduction (%)
	Min.	**Max.**	**Avg.**	**Min.**	**Max.**	**Avg.**	**Min.**	**Max.**	**Avg.**	**Avg.**
SCAQMD Method 100.1[2]	---	---	---	---	---	---	N/A	N/A	6.6	N/A
Portable Analyzer [3]	37.9	43.5	40.9	36.4	44.0	40.1	6.9	10.2	8.4	79.5
CEMS [4]	19.3	64.7	30.7	---	---	---	0.8	15.9	7.2	77

Notes:
1) Concentrations are presented in parts per million by volume dry (ppmvd) at 15% O_2.
2) Method 100.1 measurements by SCEC were performed at the stack exhaust only.
3) NOx concentrations by portable analyzer are measured routinely starting on April 7, 2010, after initial mapping of the SCR system.
4) NOx and CO CEMS data is based on an average of the 15-minute average NOx and CO concentrations for each calendar day. CEMS data was not collected at the Cat Ox outlet.
5) N/A indicates not applicable.

Table 3-11:
Count of Periods and Events with NOx Concentration Above 11 ppmvd

Number of 15-minute periods when NOx stack exhaust concentration exceeded 11 ppmvd		Total High NOx Outlet Events[4]	% of Total Operating Time[5]
Operational Issues and System Adjustments[1, 2]	703	7	3.3
Engine start-up (30 minutes)[3]	56	29	0.3
Total Non-Valid	**759**	**36**	**3.6**
Increase in NG Fuel Composition	43	17	0.2
High Load (>100%)	63	22	0.3
Other	75	22	0.4
Total Valid	**181**	**61**	**0.9**
Total	**940**	**97**	**4.5**

Notes:
1) Operational issues occurred 7/1/10-7/4/10, 12/29/10-1/4/11, 3/14/11, 3/17/11, and 3/22/11.
2) NOx at the stack exhaust exceeded 11 due to system adjustments to the urea injection system.
3) The first 30 minutes after start-up of the engine are exempt from amended Rule 1110.2. Data was excluded where NOx at the stack exhaust exceeded 11 ppmvd during engine start-up.
4) An "event" is defined as one or more consecutive 15-minute periods or periods in close succession where the NOx outlet concentration exceeded 11 ppmvd.
5) The total engine operating time is 21,285 15-minute periods (approximately 5,321 hours).

Table 3-12:
Summary of All vs. Validated NOx Inlet and Outlet Concentrations

Parameter	NOx Engine Exhaust (ppmvd)	All NOx Stack Exhaust (ppmvd)	Validated NOx Stack Exhaust (ppmvd)
Average	30.68	7.53	7.16
Minimum	10.72	0.80	0.80
Maximum	64.70	45.23	15.88
Number NOx Stack Exhaust Periods > 11 ppmvd	N/A	940	181
Percentage of 15-minute periods > 11 ppmvd	N/A	4.4%	0.9%

Notes:
1) Concentrations are presented in parts per million by volume dry (ppmvd) at 15% O_2.
2) NOx CEMS data is based on the 15-minute average NOx concentrations from June 8, 2010 through March 31, 2011.
3) N/A indicates not applicable

Table 3-13:
Ammonia Concentration Sampling Event Summary

Date	Engine Load (%)	Free NH_3 Field Measurement[1] (ppmv)	Total NH_3 Calculated Value[2] (ppmv)	Free NH_3 SCAQMD Method 207.1 (ppmv)
4/7/2010 & 4/8/2010	65	<MDL	1.66	0.12
	90			0.18
	105			0.43
4/21/2010	110	<MDL	0.09	N/A
4/29/2010	90	<MDL	0.00	N/A
5/6/2010	94	<MDL	2.18	N/A
5/19/2010	100	<MDL	2.54	N/A
6/29/2010	100	<MDL	0.97	N/A
7/28/2010	100	<MDL	0.63	N/A
8/12/2010	95	<MDL	2.50	N/A
11/4/2010	100	<MDL	4.95	N/A
1/12/2011	100	<MDL	0.32	N/A
2/24/2011	100	<MDL	0.09	N/A
5/10/2011	70	<MDL	1.12	0.37
	90		1.60	0.31
	110		3.12	0.38

Notes:
1) Free ammonia field measurements are taken using MDL to 2.5-3 ppm range and 2 to 30 ppm range Draeger® tubes.
2) Total ammonia was determined based on the theoretical calculation which uses NOx inlet and NOx outlet of the catalytic oxidizer/ SCR system and the urea injection rate. The calculated value reported is based on the 15-minute block averages from the CEMS for the time period when the exhaust gas sample was taken for the field measurement. No correction factor was applied.
3) <MDL: below Method Detection Limit.
4) N/A indicates not applicable. No data was taken using Method 207.1 during these field measurement events.

Table 3-14:
Catalytic Oxidizer /SCR System Performance Proposal

Urea usage estimate (32.5% urea solution) @ 80% NOx reduction	1.1 gallons/hour
Estimated pressure drop across catalytic oxidizer using a 4040 arrangement with one layer of standard depth (~ 3.5") catalyst elements @ 200 CPSI = A	0.7 in. wc.
Estimated pressure drop across SCR converter using a 4040 arrangement with two layers of standard depth (~ 3.5") catalyst elements @ 200 CPSI = B	1.4 in. wc.
Estimated pressure drop across 12 foot long mixing duct with one static mixer installed = C	1.9 in. wc.
Total system pressure loss estimate (includes loss through oxidation converter, SCR converter, expansion joint, and mixing duct) using 4040 oxidation catalyst and two layers of 4040 SCR catalyst (A + B + C)	4.0 in. wc.
Estimated pressure drop across one additional layer (~ 3.5") of either catalytic oxidizer or SCR elements that are 200 CPSI	0.7 in. wc.
Additional system pressure drop loss estimate if an additional layer (~ 3.5") of 100 CPSI catalyst in the 4040 housing is employed	0.4 in. wc.
Additional system pressure drop loss estimate if an additional layer (~ 2") of 200 CPSI catalyst in the 4040 housing is employed	0.3 in. wc.

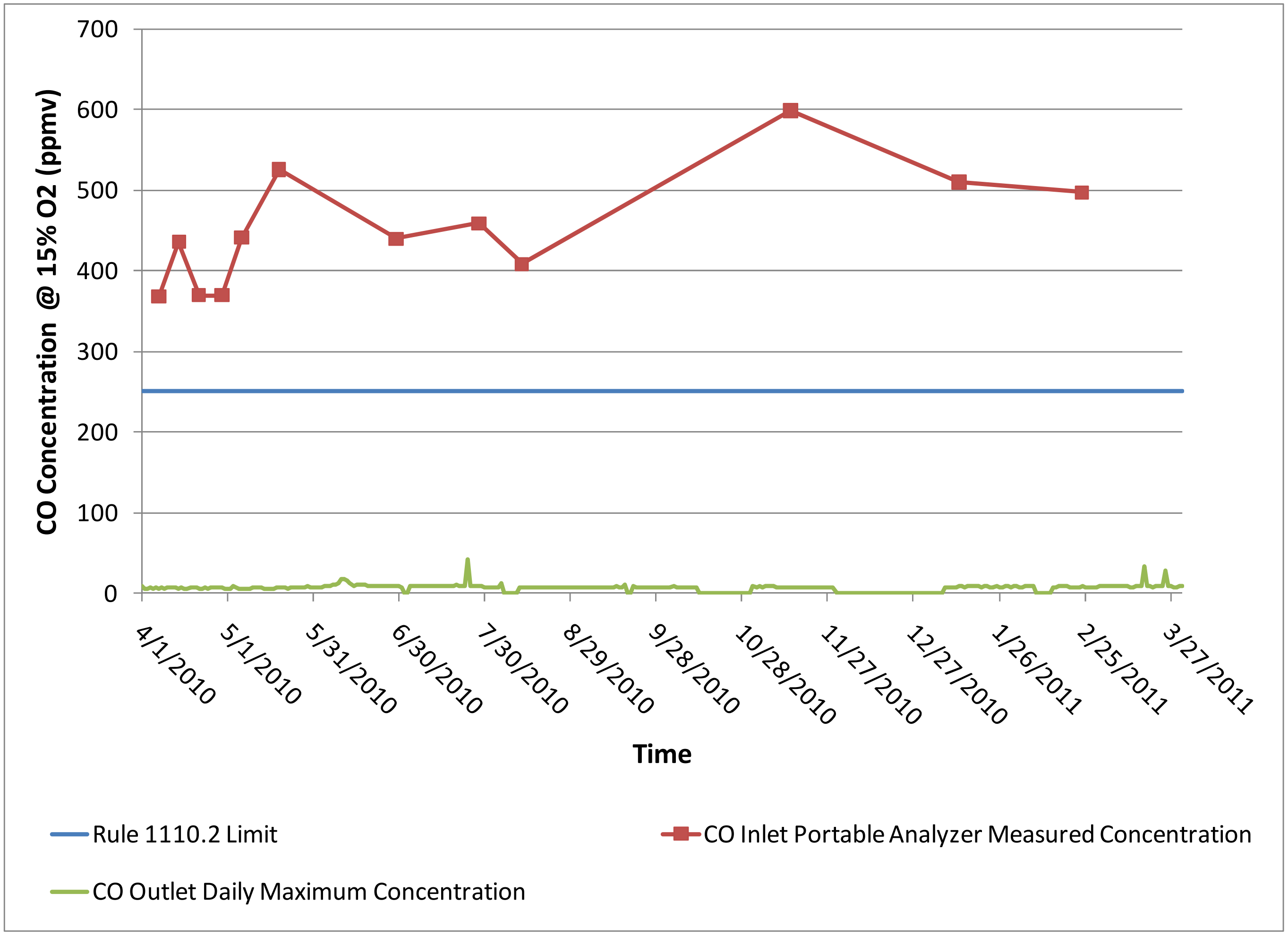
Notes: Estimates provided by Johnson Matthey in their system proposal, dated May 8, 2009.

Table 3-15:
Catalytic Oxidizer /SCR System Performance Data

	Unit	Average Value
Urea Injection Rate	gallon per hour	0.62
Catalytic Oxidizer Inlet Temperature	°F	781
Catalytic Oxidizer Outlet Temperature	°F	779
Catalytic Oxidizer Differential Pressure	in. wc.	0.3
SCR Inlet Temperature	°F	796
SCR Outlet Temperature	°F	756
SCR Differential Pressure	in. wc.	1.0

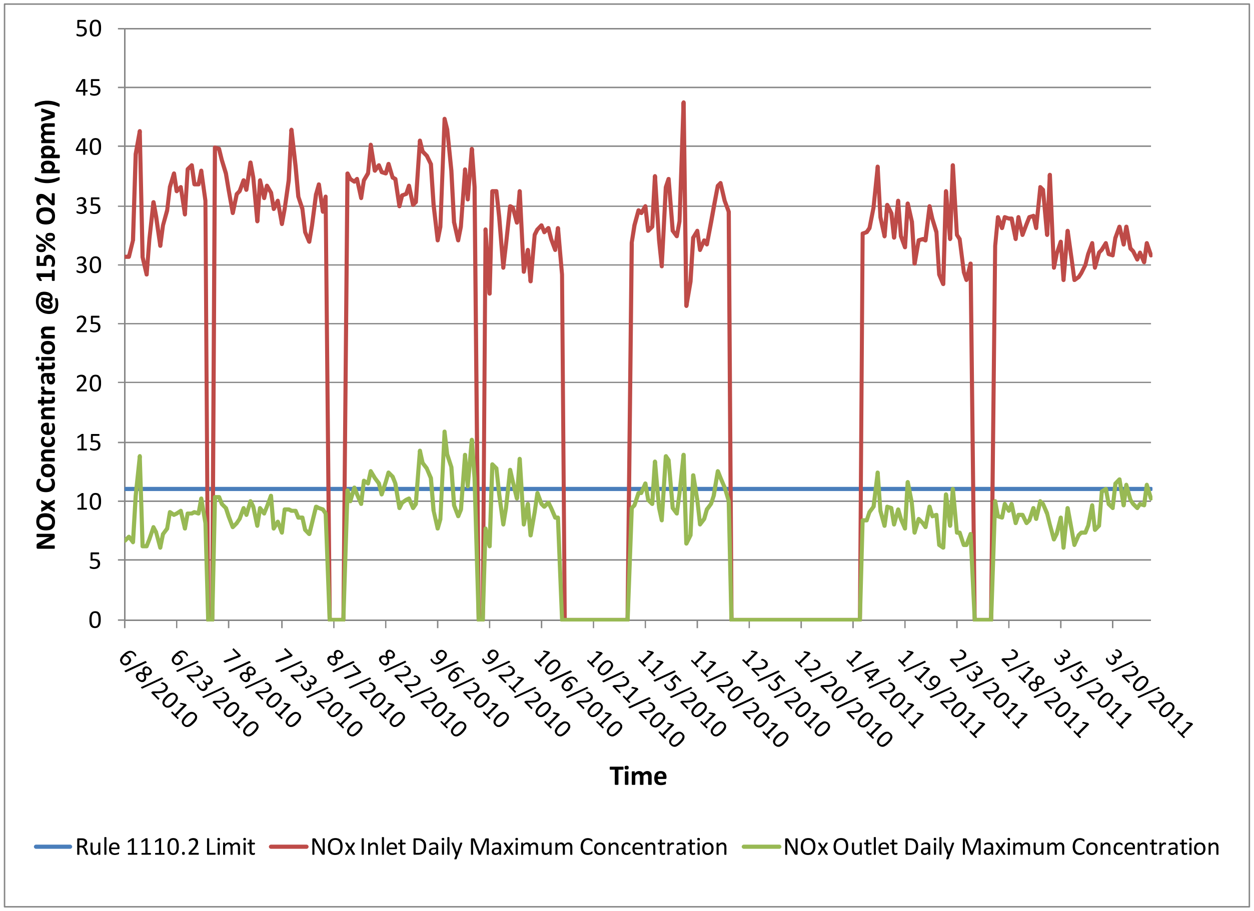
Notes: 1) Estimates are provided by the data logger located inside of the urea injection cabinet for the period of April 1, 2010 through November 4, 2010 and January 1, 2011 through February 24, 2011.
2) The data have been validated to remove periods where the engine was offline, as indicated when urea injection is offline, temperatures in the catalysts cool and NOx inlet value drop.

Figure 3-1: Catalytic Oxidizer Inlet and Outlet CO Concentration



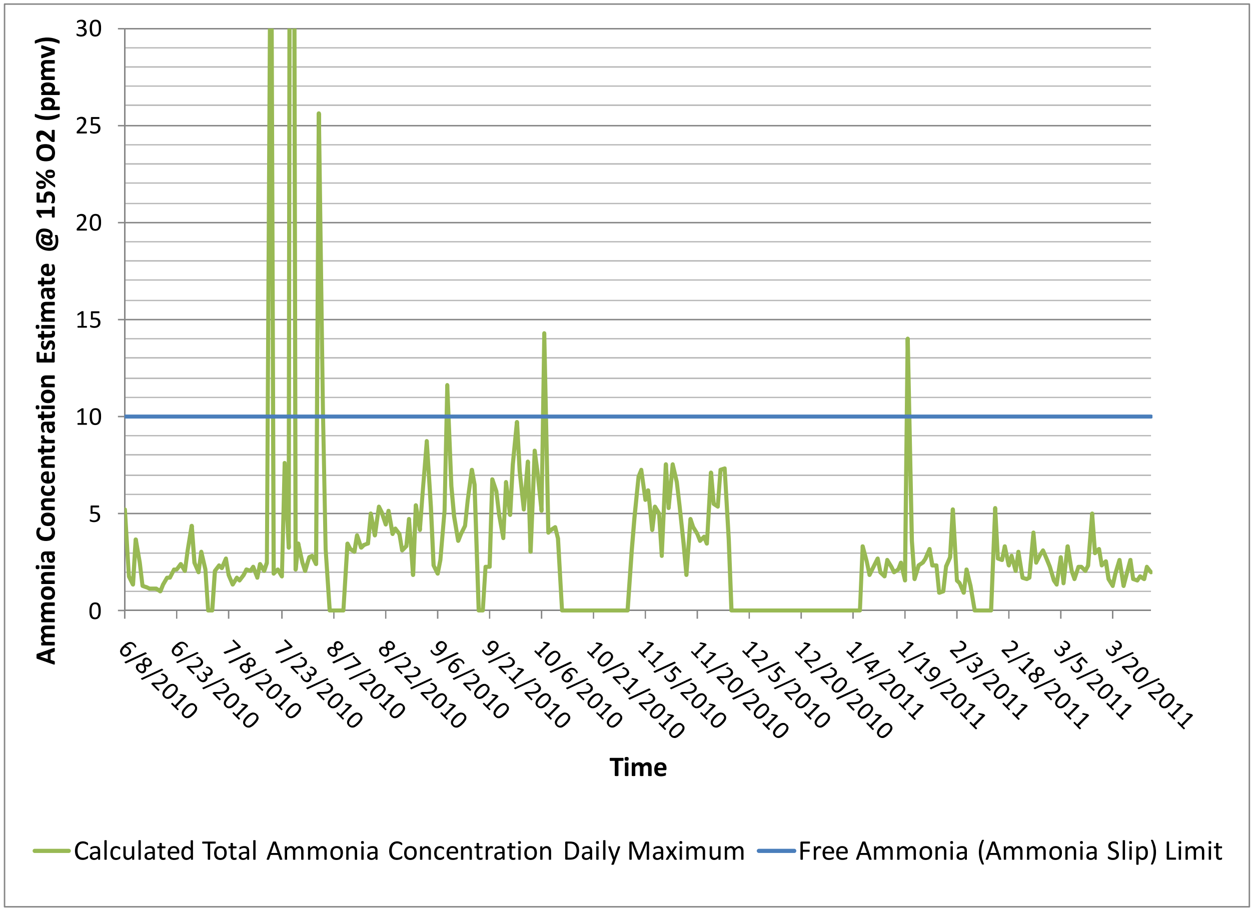
Notes:
1) The first 30 minutes after start-up of the engine are exempt from amended Rule 1110.2. Data was excluded where NOx at the stack exhaust exceeded 11 ppmvd during engine start-up.
2) CEMS values shown are maximum values for each calendar day and may not all occur at the same time as the portable analyzer measurement.
3) Spikes where inlet and outlet NOx concentrations drop to 0 ppmv occur when the engine is offline.

Figure 3-2: Selective Catalytic Reduction Inlet and Outlet NOx Concentration



Notes:
1) The first 30 minutes after start-up of the engine are exempt from amended Rule 1110.2. Data was excluded where NOx at the stack exhaust exceeded 11 ppmvd during engine start-up.
2) Data was excluded where NOx at the stack exhaust exceeded 11 due to system adjustments to the urea injection system.
3) Data was excluded where operational issues occurred from 7/1/10-7/4/10, 12/29/10-1/4/11, 3/14/11, 3/17/11, and 3/22/11.
4) Values shown are maximum values for each calendar day and may not all occur at the same time within the day.
5) Spikes where inlet and outlet NOx concentrations drop to 0 ppmv occur when the engine is offline.

Figure 3-3: Selective Catalytic Reduction Estimated Total Ammonia Concentration



Notes:
1) The first 30 minutes after start-up of the engine are exempt from amended Rule 1110.2. Data were excluded where NOx at the stack exhaust exceeded 11 ppmvd during engine start-up.
2) Data were excluded where the SCR system was offline due to system adjustments to the urea injection system.
3) Data were excluded where operational issues occurred from 7/1/10-7/4/10, 12/29/10-1/4/11, 3/14/11, 3/17/11, and 3/22/11.
4) Values shown are maximum 15-minute values for each calendar day.
5) Spikes where inlet and outlet ammonia concentrations drop to 0 ppmv occur when the engine is offline.
6) Ammonia concentration values reported on July 20, 2010 and July 26, 2010 occurred within one hour of an engine shutdown or startup and were not part of the 30-minute exemption from amended Rule 1110.2.

4. Cost Effectiveness Analysis

A cost analysis for the implementation of the DGCS and Cat Ox/SCR systems at Plant 1 Engine 1 was performed. The cost analysis was developed for one digester gas cleaning vessel, with an approximate capacity of 9,900 lbs of carbon media and associated piping, and one Cat Ox/SCR system with platform installation.

4.1. Capital and Operation & Maintenance Costs

The capital project budget includes the following construction costs: equipment; installation; mechanical; structural; electrical; site/architectural; instrumentation; and material sales tax; as well as the construction contractor's expenses, such as contractor overhead, profit, mobilization, bonding, and insurance. For capital cost the following assumptions apply:

- The construction cost subtotal is time dated for June 2009 and based on the pilot test construction contract price, including change orders.
- The equipment cost is time dated for June 2009 and based on the pilot test costs of the following equipment: one Cat Ox/SCR system with urea injection control cabinet for Plant 1 Engine 1; one digester gas cleaning vessel with inlet, outlet, and bypass piping sized to treat 100 percent of the digester gas for the Plant 1 cogeneration facility; one NOx probe and umbilical sample line from the Engine 1 exhaust to the CEMS panel in the control room; and seven expansion joints for the engine exhaust ductwork.
- Project design and engineering is assumed to be 15% of the total construction and equipment cost.
- The annualized total capital project budget is based on a 20-year evaluation period and 4.0 percent annualized rate, as set forth in the SCAQMD July 9, 2010 Board Meeting Minutes, Attachment B: Assessment of Available Technology for Control of NOx, CO and VOC Emissions from Biogas-Fueled Engines – Interim Report.

Annual O&M costs associated with operating the digester gas cleaning system and Cat Ox/SCR system includes the following components:

- Annual additional electrical cost;
- Annual carbon media replacement costs;
- Oxidation and SCR catalyst replacement costs;
- Annual urea usage costs;
- Annual equipment maintenance costs;
- Periodic siloxane, VOC, and H_2S testing;

- The reduction in O&M costs due to the use of clean digester gas was considered. Such reduction in O&M costs includes a reduction in frequency of major maintenance interval service and maintenance shutdowns related to siloxane compounds present in the digester gas.
- The reduction in annual emissions fees for NOx, VOC, CO, and formaldehyde based on the estimated emissions reductions realized from the engine exhaust control system was considered.

The assumptions related to the O&M costs are the following:

- Annual operating hours of a single engine at Plant 1 is estimated to be 6,000 hours.
- The change-out of the carbon media for the digester gas cleaning system is estimated to be approximately $40,000 per change-out. The change-out frequency with three engines operating at Plant 1 at 6,000 annual operating hours is approximately three (3) times per year. The total annual cost of carbon media for three engines at 6,000 annual operating hours is $120,000 per year. Therefore, the cost for carbon media for a single engine is approximately $40,000 per year.
- The replacement of the sixteen catalytic oxidizer media blocks and thirty-two SCR catalyst media blocks is estimated to take place once every three years for each engine. Although the Cat Ox/SCR system demonstrated performance for one year during the pilot testing period, it is assumed that the media will perform for three years based on the vendor warranty of 16,000 operating hours. Assuming that each engine operates for 6,000 hour per year, the engine should reach 16,000 operating hours in 2 years and 8 months. The costs of each catalytic oxidizer media block and SCR catalyst media block are $3,450 and $1,850, respectively.
- Urea cost is assumed to equal $4.50 per gallon, including tax, at an average rate of 0.7 gallons per hour for 6,000 annual operating hours.
- Equipment maintenance and testing is assumed to equal $5,000 per year for annual maintenance of the SCR urea injection system, $5,400 per year for siloxane testing ($600 per sample, 3 samples per change out, and 3 change outs per year), and $3,000 per year for VOC and H_2S sampling.
- Annual reduced engine maintenance cost using cleaned digester gas, assumed to equal $130,641 for three engines operating at 6,000 hours annually. Therefore, the approximate savings per engine is approximately $43,547 per year as estimated by OCSD. Currently, the three engines at Plant 1 are consuming all of the digester gas produced by the facility. Therefore, although the annual cost of maintenance is decreased, the total operating time of each engine will remain the same.
- Calculation of emissions reductions for NOx, VOC, and CO is provided in Scenario 2 in Section 4.2 below. Scenario 2 assumed that the uncontrolled NOx, VOC, and CO emissions were based on the results from the 2011 Annual Compliance Test for Engines 2 and 3. The controlled emissions were based on the Rule 1110.2 limits of 11 ppmv for NOx and 30 ppmv for VOCs, and the pilot testing results of 15 ppmv for CO. Fees per ton of NOx, VOC, and CO are assumed to be $270.26, $576.75, and

$3.57, respectively, based on the Annual Emission Report provided by the OCSD dated February 23, 2011.

- The uncontrolled emissions of formaldehyde were based on the results of the 2009 Annual Compliance Test for Engine 3 of 1.4 lb/hr. The controlled emissions of formaldehyde were based on the results of the 2011 Annual Compliance Test for Engine 1 of 0.069 lb/hr. It is assumed that the annual operating hours of a single engine at Plant 1 is 6,000 hours. Therefore, formaldehyde emissions reduction is 4.13 tons per year. The fee per ton of formaldehyde is assumed to be $800.00 based on the Annual Emission Report provided by the OCSD dated February 23, 2011.
- Annual O&M costs do not include the cost of ammonia sampling because it is assumed that ammonia sampling is part of the annual compliance test. The estimated ammonia sampling cost is $2,500 for one sampling event per year using SCAQMD Method 207.1. The annual cost of weekly ammonia testing using Draeger® tubes or similar colorimetric tubes is assumed to equal $300.

The capital cost and annual O&M costs for a single engine is presented in Table 4-1.

4.2. Unitized Cost of Carbon Media and Emissions Reduction

The cost of implementation of the DGCS and Cat Ox/SCR systems can be unitized as a cost per cubic foot of digester gas treated or as a cost per ton of NOx and VOC reduced in the emissions. The following summarizes these metrics for evaluating costs.

4.2.1. Cost for Volume of Digester Gas Treated

A metric for evaluating the cost of the DGCS is the cost per cubic foot of digester gas treated. This metric is based on the frequency of the carbon media change-out as well as the cost per change-out. The digester gas volume that passed through the catalyst during the pilot test ranged from 146 MMcf to 169 MMcf. The cost of each carbon media change-out is assumed to be approximately $40,000. Therefore, the cost per treated digester gas ranges between $237/MMcf and $274/MMcf. The capacity of the digester gas cleaning vessel is 9,900 pounds of carbon media. Therefore the media per volume of treated digester gas ranges between 59 lbs/MMcf and 68 lbs/MMcf. Note that these are conservative estimates. The pilot test only utilized a single digester gas cleaning vessel as opposed to a lead/lag configuration in which two vessels, a lead vessel followed by a second lag vessel, are used. Therefore, the carbon media was replaced more frequently than necessary to prevent potential breakthrough of siloxane compounds that may foul the catalyst. In a lead/lag configuration, the volume of gas treated between change-outs can be extended since breakthrough can be allowed to occur in the lead vessel because any siloxane compounds would be removed in the lag vessel.

4.2.2. Cost for Reductions in NOx and VOCs, and CO Emissions

A metric for evaluating the cost effectiveness of the Cat Ox/SCR system is cost per ton of NOx, VOC, and CO removed by the system. Based on the total annualized cost per engine, two scenarios for estimating NOx, VOC, and CO emissions reduced were developed. The following are the assumed uncontrolled and controlled concentrations for the two scenarios:

Scenario 1

- Uncontrolled concentrations are based on the current permit limits of 45 ppmv of NOx, 209 ppmv of VOCs, and 2,000 ppmv of CO, each at 15% O_2.
- Controlled emissions are based on the future Rule 1110.2 limits of 11 ppmv of NOx and 30 ppmv of VOCs, each at 15% O_2. Controlled emissions for CO are based on 15 ppmv because the Cat Ox/SCR system consistently reduced CO emissions well below the Rule 1110.2 limit of 250 ppmv. The concentration of 15 ppmv provides a factor of safety of 2 over the average CO concentration of 7.5 ppmv. The factor of safety gives credit for projected emissions reduction, but allows for reduced efficiency as the catalyst approaches the end of its lifecycle, prior to replacement.

Scenario 2

- Uncontrolled concentrations from the 2011 Annual Source Test Report are 31 ppmv of NOx, 97 ppmv of VOCs, and 371 ppmv of CO at 15% O_2 for Plant 1 (Engines 2 and 3).
- Controlled emissions are based on the future Rule 1110.2 limits of 11 ppmv of NOx and 30 ppmv of VOCs, each at 15% O_2. Controlled emissions for CO are based on 15 ppmv because the Cat Ox/SCR system consistently reduced CO emissions well below the Rule 1110.2 limit of 250 ppmv. The concentration of 15 ppmv provides a factor of safety of 2 over the average CO concentration of 7.5 ppmv. The factor of safety gives credit for projected emissions reduction, but allows for reduced efficiency as the catalyst approaches the end of its lifecycle, prior to replacement.

The assumptions used for each scenario were:

- Annual operating hours of a single engine at Plant 1 is estimated to be 6,000 hours;
- Exhaust flowrates are based on high load; and
- VOCs emissions are calculated as methane.

Table 4-2 provides a summary of the cost effectiveness for the two scenarios for one engine at Plant 1. The cost effectiveness in terms of dollars per ton of NOx and VOCs reduced for Scenarios 1 and 2 was $7,987 and $17,585, respectively. The cost effectiveness in terms of dollars per ton of CO reduced for Scenarios 1 and 2 was $363 and $3,546, respectively. Note that the cost effectiveness for CO is conservative since the annualized cost is based on the entire system including the SCR and urea injection system.

Table 4-1:
Estimated Capital and O&M Costs for Plant 1 Engine 1

Capital Cost	**Plant 1 Engine 1[1]**
Equipment (Cat Ox/SCR, DGCV, CEMS, Expansion Joints)	$708,000
Labor and Contractor Cost[2]	
Bonding/Insurance	$21,272
Mobilization	$56,748
Prime Contractor Labor and Construction (i.e. concrete & rebar, piping, fittings, valves, installation & start-up, management, etc.)	$765,723
Steel Subcontractor (i.e. structural steel, miscellaneous metal, handrail, grating)	$249,941
Insulation Subcontractor	$82,879
Electrical Subcontractor (i.e. wiring, conduit, grounding, etc.)	$76,311
Painting Subcontractor	$28,655
Labor and Contractor Cost Subtotal (including contractor markups for overhead, profit, mobilization, bonding, insurance)	$1,281,529
Construction Subtotal (June 2009 dollars)	$1,989,529
Project Design and Engineering (15% of construction subtotal)	$298,429
Total Capital Cost	$2,287,958
Annualized Capital Cost (4 % annual rate, 20 years)	$168,352
Annual O&M Cost for 1 Engine (operating 6,000 hrs/yr)[3]	**Plant 1 Engine 1**
Carbon Media Replacement	$40,000
Catalyst Replacement	$38,133
Urea Cost	$18,900
Electrical Cost	$1,200
Equipment Maintenance and Testing	$13,400
Reduced Engine Maintenance	$(43,547)
Reduced Emission Fees	$(9,136)
Annual O&M Cost per Engine	$58,950
Total Annual Capital and O&M Cost for 1 Engine	**Plant 1 Engine 1**
Total Annualized Cost per Engine	**$227,302**

Notes:
1) Engine Size: 2,500 kW/3,471 bhp
2) Subcontractor costs include a 10% prime contractor markup.
3) Assumptions for the basis of O&M costs is provided in Section 4.1.

Table 4-2:
Cost per Ton NOx and VOC Emissions Reduced at Plant 1 Engine 1

Capital Cost	**Plant 1 Engine 1**
Annualized Capital Cost (4 % annual rate, 20 years)	$168,352
Annual O&M Cost per Engine[1,2]	$58,950
Total Annualized Cost per Engine	**$227,302**
Scenario 1	**Plant 1 Engine 1**
Uncontrolled NOx – Current Permit Limit (ppmv)	45
Controlled NOx – Future Rule 1110.2 Limit (ppmv)	11
Uncontrolled VOC – Current Permit Limit (ppmv)	209
Controlled VOC – Future Rule 1110.2 Limit (ppmv)	30
Uncontrolled CO – Current Permit Limit (ppmv)	2,000
Controlled CO (ppmv)[3]	15
NOx Reduction (ton/yr)	10.05
VOC Reduction (ton/yr)	18.41
CO Reduction (ton/yr)	357.21
Cost Effectiveness ($/ton of NOx and VOC reduced)	**$7,987**
Cost Effectiveness ($/ton of CO reduced)	**$636**
Scenario 2	**Plant 1 Engine 1**
Uncontrolled NOx – 2011 Source Testing Data (ppmv)	31
Controlled NOx – Future Rule 1110.2 Limit (ppmv)	11
Uncontrolled VOC (ppmv)	97
Controlled VOC – Future Rule 1110.2 Limit (ppmv)	30
Uncontrolled CO – 2011 Source Testing Data (ppmv)	371
Controlled CO (ppmv)[3]	15
NOx Reduction (ton/yr)	6.03
VOC Reduction (ton/yr)	6.89
CO Reduction (ton/yr)	64.10
Cost Effectiveness ($/ton of NOx and VOC reduced)[4]	**$17,585**
Cost Effectiveness ($/ton of CO reduced)[4]	**$3,546**

Notes:
1) Engine Size: 2,500 kW/3,471 bhp
2) Annual Operating Hours: 6,000 hours/year
3) Controlled emissions for CO are based on 15 ppmv because the Cat Ox/SCR system consistently reduced CO emissions well below the Rule 1110.2 limit of 250 ppmv. The concentration of 15 ppmv provides a factor of safety of 2 over the average CO concentration of 7.5 ppmv.
4) Cost effectiveness of NOx and VOC reduced and CO reduced are calculated separately. The cost effectiveness of NOx and VOC is equal to the annualized cost per engine divided by the sum of NOx and VOC tons per year reduced. The cost effectiveness of CO is equal to the annualized cost per engine divided by the CO tons per year reduced and does not take NOx or VOC reduction into consideration.

5. Conclusions and Recommendations

In order to evaluate if the amended Rule 1110.2 limits could be met for their digester gas-fired IC engines, OCSD proposed to perform a pilot study on Engine 1 at Plant 1. In previous studies, OCSD had identified a catalytic oxidizer and SCR system along with a DGCS as the most feasible technology to lower air toxic emissions and to meet the new lower emissions limits. Because SCAQMD recognized that the emission limits in the new Rule 1110.2 were "technology-forcing," they provided a grant to OCSD to support the pilot study at Plant 1 Engine 1 as part of a Rule 1110.2 technology assessment study to determine if cost-effective and commercial technologies are available to comply with the new lower emission limits. The 12-month pilot study at Plant 1 evaluated the effectiveness of the control systems to meet Rule 1110.2 limits.

5.1. System Performance

The DGCS system, in general, removed siloxanes from the digester gas to below MDL levels and significantly reduced sulfur compounds and VOCs successfully reducing catalyst masking which should lead to extended catalyst life. Additional benefits of the contaminant removal were significant improvements in engine maintenance requirements, and lower O&M costs. The use of cleaned digester gas resulted in much less frequent maintenance requirements for the engine, including longer time intervals between spark plug changes and major maintenance events.

There were no notable back pressure effects on engine performance due to the installation of the Cat Ox/SCR system with a DGCS during the pilot test. The system design back pressure for the Cat Ox/SCR system and additional exhaust ductwork was estimated to not exceed 9 in. wc. per the engine manufacturer's recommendations. Based on the data monitored during the pilot test, the average differential pressure through the catalytic oxidizer and SCR systems are approximately 0.3 and 1.0 in. wc, respectively.

The combined Cat Ox/SCR system with digester gas cleaning evaluated in the pilot study resulted in significant reductions in CO, VOC, and NOx emissions from the digester gas fired IC engine at Plant 1 providing substantial air quality benefits from this system. In addition, NOx and CO, along with VOCs (as NMNEOCs) are considered indirect greenhouse gases, affecting tropospheric ozone and methane levels.

5.2. Comparison to Rule 1110.2 Limits and Other Criteria

- The average NOx concentration at the stack exhaust after the pilot study Cat Ox/SCR system was approximately 7 ppmv, below the 11 ppmv under amended Rule 1110.2. The lowest NOx stack exhaust concentration met consistently under all valid conditions was 16 ppmv. While there were some periods when the NOx stack exhaust concentration was above 11 ppmv; after screening these periods to eliminate unusual operational events or start-up conditions, 181 periods out of 21,285 total operating periods (approximately 5,321 hours) remained as valid periods where the NOx stack exhaust concentration was above the new Rule 1110.2 limit. These periods occurred during 61 separate events and accounted for less than 0.9% of the total measurement periods during the pilot study.

- Free ammonia (ammonia slip), the result of excess urea injection in the SCR system, was below 0.5 ppmv using SCAQMD compliance sampling methods and below the MDL using Draeger® tubes over the course of the pilot study. The total ammonia calculation method, unlike the measurement methods for free ammonia, did predict low levels of total ammonia. It was noted that the total ammonia calculation method estimates did not include the use of a project-specific correction factor, CF, which could be used to account for secondary reactions that would consume ammonia, thus bringing the total ammonia calculation method estimates more in line with the measurements of free ammonia.
- The maximum CO concentration at the stack exhaust (42.2 ppmv) was well below the amended Rule 1110.2 emission limit of 250 ppmv.
- The maximum VOC concentration at the stack exhaust (4.95 ppmv) was consistently well below the 30 ppmv in amended Rule 1110.2.

Therefore, with the exception of a relatively limited number of periods when the NOx stack exhaust concentration was above the new amended Rule 1110.2 limit, the combined Cat Ox/SCR system equipped with a DGCS was able to meet the new emission limits.

5.3. Cost Effectiveness

The total capital costs to design, procure, and install a digester gas cleaning vessel to clean all the digester gas to the Plant 1 engines, and a Cat Ox/SCR system with auxiliary equipment for Engine 1 is estimated to be $2,300,000. The annual O&M cost for these systems at Plant 1 is approximately $59,000. Assuming a 20-year lifespan, the total annualized cost (capital cost plus O&M) for the DGCS and Cat Ox/SCR systems for Plant 1 Engine 1 is $227,000.

The cost effectiveness analysis (based on dollars per ton of NOx, VOC and CO emissions reduced) was developed for two scenarios: Scenario 1 assumed that the uncontrolled emissions were based on permit limits (i.e., 45 ppmv, 209 ppmv, and 2,000 ppmv, respectively), and Scenario 2 assumed that the uncontrolled emissions were based on the results from the 2011 Annual Compliance Test for Engines 2 and 3. Both scenarios assumed that the controlled emissions were based on the Rule 1110.2 limits of 11 ppmv for NOx, 30 ppmv for VOCs, and the pilot testing results of 15 ppmv for CO. Under these assumptions, the cost effectiveness estimates for Scenarios 1 and 2 are $7,987 and $17,585, respectively, per ton of NOx plus VOCs reduced. The cost effectiveness estimates for Scenarios 1 and 2 are $636 and $3,546, respectively, per ton of CO reduced.

Note that the cost effectiveness for CO is conservative since the annualized cost is based on the entire system including the SCR and urea injection system. The annualized cost and emissions reduced calculations were based on operating each engine for a maximum of 6,000 hours per year.

5.4. Recommendations

SCR systems similar to the Johnson Matthey system used in the present pilot study are commercially available and have successfully demonstrated NOx control for single fuels, such as natural gas. However, based on previous source testing data, the NOx concentration is higher for natural gas than digester gas at a given load; therefore, there is a potential for variations in NOx concentration at the inlet to the SCR system at a given load due to the varying fuel blend in biogas-fueled engines. Since the urea injection rate can only be established based on engine load and not inlet NOx concentration, it is difficult to maintain a targeted NOx limit at the stack exhaust using this type of SCR system.

NOx concentrations in the stack exhaust were above the amended Rule 1110.2 NOx limit of 11 ppmv for a small number of sampling periods during the pilot study. These periods where the NOx stack exhaust concentration was over 11 ppmv may indicate that this limit is too conservative, especially for biogas-fueled and dual-fueled engines where a steady SCR control efficiency is difficult to maintain. Recommendations regarding the new amended Rule 1110.2 NOx limit of 11 ppmv are as follows:

1. Given the variations in the engine load and urea injection rate mapping requirements for the digester gas-fired IC engine, using the 15-minute block average for compliance with the NOx emission limit may also be too restrictive, and a longer averaging time may be more appropriate for biogas-fired engines. Alternatively, allowing a limited number of excursions above the 11 ppmv for biogas-fueled engines, for example, 5% of the total annual continuous (i.e., 15-minute averaging periods) NOx data, to account for the difficulty in accurately mapping the urea injection rate to control NOx outlet concentration, may also be warranted.

2. In April 2011, after the official pilot testing period concluded, a Johnson Matthey technician adjusted the urea injection rate curve to 1) expand the curve to a maximum of 125% engine load and 2) to increase the urea injection rate at high engine loads. The increase in urea injection rate should accommodate for the increased NOx production when the engine combusts a fuel blend with a higher percentage of natural gas. Further observation will be required to confirm if these adjustments will lead to a reduction in the number of periods where stack exhaust NOx outlet concentration is above 11 ppmv.

Further sampling of the exhaust emissions can be performed to establish a correction factor for the estimated total ammonia calculation method and to confirm that the SCR system does not produce measureable free ammonia. Recommendations regarding the estimated total ammonia calculation method are as follows:

3. The presence of sulfur dioxide and sulfur trioxide in the exhaust gas before the SCR, and ammonium sulfate and ammonia bisulfate in the exhaust gas after the SCR, can indicate secondary reactions between the ammonia and sulfur compounds in the exhaust gases taking place due to the injection of urea. The correction factor, CF, can be used in the estimated total ammonia calculation method to account for these reactions, thus improving this calculation for estimating free ammonia.

4. Although the pilot study data indicates that there is minimal, if any, free ammonia due to the SCR system, it is recommended that the OCSD perform additional and routine testing for free ammonia during varying loads and fuel blends over a period of time to accumulate data corroborating that the SCR system does not produce measurable free ammonia under all operating conditions for a given mapped urea injection versus engine load set point.

ATTACHMENT C

APPENDIX A, B, AND C OF ORANGE COUNTY SANITATION DISTRICT FINAL REPORT

APPENDIX A-1:

SCAQMD Permit to Construct/Operate
for an Experimental Research Project

South Coast
Air Quality Management District
21865 Copley Drive, Diamond Bar, CA 91765-4178
(909) 396-2000 · www.aqmd.gov

October 15, 2009
A/N 497717

ORANGE COUNTY SANITATION DISTRICT
10844 Ellis Avenue
Fountain Valley, CA 92708

Attention: Mike D. Moore
Manager - Environmental Compliance & Regulatory Affairs

Gentlemen:

PERMIT TO CONSTRUCT / OPERATE FOR AN EXPERIMENTAL RESEARCH PROJECT

The system described below is granted a Permit to Construct and Operate (Application Number 497717) as allowed by and under the conditions set forth by Rule 441 of the Rules and Regulations of the South Coast Air Quality Management District and is subject to the special conditions listed.

EQUIPMENT DESCRIPTION:

DIGESTER GAS FUEL PRETREATMENT, POST-COMBUSTION CATALYTIC OXIDATION AND SELECTIVE CATALYTIC REDUCTION SYSTEMS FOR ENGINE NO. 1 (PO G2957), CONSISTING OF;

1. DIGESTER GAS (DG) CLEANING VESSEL, 7.5' DIA. X 8' H., CONTAINING MINIMUM OF 9,500 LBS OF GRANULAR ACTIVATED CARBON MEDIA, WITH ASSOCIATED DIGESTER GAS SUPPLY AND RETURN LINES, VALVES, TEMPERATURE, DIFFERENTIAL PRESSURE DROP GAUGES, AND CONDENSATE DRIP TRAP.

2. CATALYTIC OXIDIZER (CATOX), JOHNSON MATTHEY INC., HOUSING MODEL NO. 4040-30-36-4, 200 CPSI OXIDATION CATALYST, ALUMINUM SUBSTRATE WITH OTHER METALS, 8' L. X 0' – 4" W. X 8' H., WITH ONE LAYER OF MODULE, 18.67 CUBIC FOOT TOTAL VOLUME, AND WITH ASSOCIATED AUTOMATIC TEMPERATURE AND PRESSURE MONITORING DEVICES AND CONTROLS.

3. SELECTIVE CATALYTIC REDUCTION (SCR) CATALYST, JOHNSON MATTHEY INC., HOUSING MODEL NO. 4040-36-4, ALUMINUM SUBSTRATE WITH OTHER METALS,, 8' L. X 0' – 4" W. X 8' H., WITH TWO LAYERS OF MODULE, 37.33 CUBIC FOOT TOTAL VOLUME, AND WITH ASSOCIATED AUTOMATIC TEMPERATURE AND PRESSURE MONITORING DEVICES, AND CONTROL SYSTEMS WITH EXISTING CONTINUOUS EMISSIONS MONITORING SYSTEM (CEMS).

4. STORAGE TANK, AQUEOUS UREA SOLUTION (32.5%), 1000 GALLON CAPACITY, WITH ASSOCIATED PIPING, PUMP, FLOW CONTROL VALVES, UREA INJECTION LANCE, COMPRESSED AIR SUPPLY, AND WITH ASSOCIATED AUTOMATIC CONTROLS.

TO BE LOCATED AT: ORANGE COUNTY SANITATION DISTRICT (OCSD)
WASTEWATER TREATMENT PLANT NO. 1
10844 ELLIS AVENUE
FOUNTAIN VALLEY, CA 92708

Conditions:

1. OPERATION OF THIS EQUIPMENT SHALL BE CONDUCTED IN COMPLIANCE WITH ALL DATA AND SPECIFICATIONS SUBMITTED WITH THE APPLICATION UNDER WHICH THIS PERMIT IS ISSUED, UNLESS OTHERWISE NOTED BELOW.

2. THIS EQUIPMENT SHALL BE PROPERLY MAINTAINED AND KEPT IN GOOD OPERATING CONDITION AT ALL TIMES.

3. THIS EQUIPMENT SHALL BE OPERATED BY PERSONNEL PROPERLY TRAINED IN ITS OPERATION.

4. THIS EXPERIMENTAL RESEARCH PERMIT SHALL EXPIRE ON OCTOBER 31, 2010.

5. SAMPLES SHALL BE COLLECTED FROM THE INLET AND THE OUTLET OF THE DIGESTER FUEL GAS CLEANING (DFGC) SYSTEM AND ANALYZED FOR TOTAL SILICON, SILOXANE AND SILOXANE COMPOUNDS, AND TOTAL SULFUR COMPOUNDS AS H2S, USING DISTRICT OR OTHER APPROVED METHODS. RESULTS SHALL BE RECORDED.

6. WHENEVER THE DFGC SYSTEM IS IN OPERATION, THE FUEL GAS FLOW RATE (SCFM) AND TOTAL VOLUME (CUBIC FEET) PROCESSED EACH DAY SHALL BE RECORDED.

7. WHEN CATALYTIC OXIDIZER IS IN OPERATION, THE OXIDIZER'S INLET AND OUTLET TEMPERATURE AND PRESSURE DROP READINGS SHALL BE RECORDED ONCE A SHIFT.

8. WHEN CATALYTIC OXIDIZER IS IN OPERATION, THE CATALYTIC OXIDIZER'S INLET AND OUTLET CO AND VOC CONCENTRATIONS (PPMV) SHALL BE MONITORED, USING A PORTABLE ANALYZER AND AQMD APPROVED TEST METHODS. READINGS SHALL BE RECORDED AT START-UP AND AT LEAST ON A WEEKLY BASIS.

9. WHEN CATALYTIC OXIDIZER IS IN OPERATION, INLET AND OUTLET SAMPLES SHALL BE COLLECTED AND SPECIATED ANALYSIS SHALL BE CONDUCTED FOR TOTAL VOCs (PPMV), INCLUDING BUT NOT LIMITED TO, FOR FORMALDEHYDE AND OTHER TOXIC COMPOUNDS PRESENT (PPMV) USING DISTRICT OR OTHER APPROVED METHODS.

10. WHEN SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM IS IN OPERATION, THE INLET AND OUTLET TEMPERATURE AND PRESSURE DROP READINGS SHALL BE RECORDED ONCE A SHIFT.

11. EXCEPT DURING STARTUP, THE OPERATOR SHALL MAINTAIN THE TEMPERATURE AT THE INLET TO THE CATALYST BEDS BETWEEN 600 AND 850 DEG. F.

12. THE OPERATOR SHALL INSTALL AND MAINTAIN A UREA FLOW RATE MEASURING SYSTEM TO ACCURATELY INDICATE THE UREA INJECTION RATE TO THE SELECTIVE CATALYTIC REDUCTION SYSTEM.

October 15, 2009

13. THE OPERATOR SHALL CONTINUOUSLY ANALYZE THE UREA INJECTION RATE, AND THE SCR INLET AND OUTLET NOX EMISSION RATE TO ESTIMATE THE AMMONIA CONCENTRATION IN THE SCR OUTLET, BASED ON ONE HOUR AVERAGE.

14. WITHIN 90 DAYS OF COMPLETION OF THE RESEARCH EXPERIMENTS, THE ORANGE COUNTY SANITATION DISTRICT SHALL SUBMIT TO AQMD A COMPLETE REPORT WITH EQUIPMENT OPERATING PARAMETERS AND EMISSIONS RESULTS TO;
ATTENTION: GAURANG RAWAL, REFINERY AND WASTE MANAGEMENT PERMITTING,
21865 COPLEY DRIVE, DIAMOND BAR, CA 91765. THE SUBMITTAL SHALL INCLUDE A COPY OF THIS PERMIT.

15. EMISSIONS FROM THIS EQUIPMENT, AVERAGED OVER 15 MINUTES, CORRECTED TO 15% O2 ON A DRY BASIS, SHALL NOT EXCEED THE FOLLOWING;

POLLUTANT	PPMVD
CO	590
NO_x	45
VOC	209
NH_3	<10
PM10	0.0087 GRAINS/DSCF

16. ALL RECORDS SHALL BE KEPT AND MAINTAINED FOR A PERIOD OF AT LEAST TWO YEARS AND SHALL BE MADE AVAILABLE TO AQMD PERSONNEL UPON REQUEST.

It is your responsibility to comply with all laws, ordinances and regulations of other government agencies, which are applicable to this equipment.

If you have any questions, please call Mr. Gaurang Rawal at (909) 396-2543.

Yours truly,

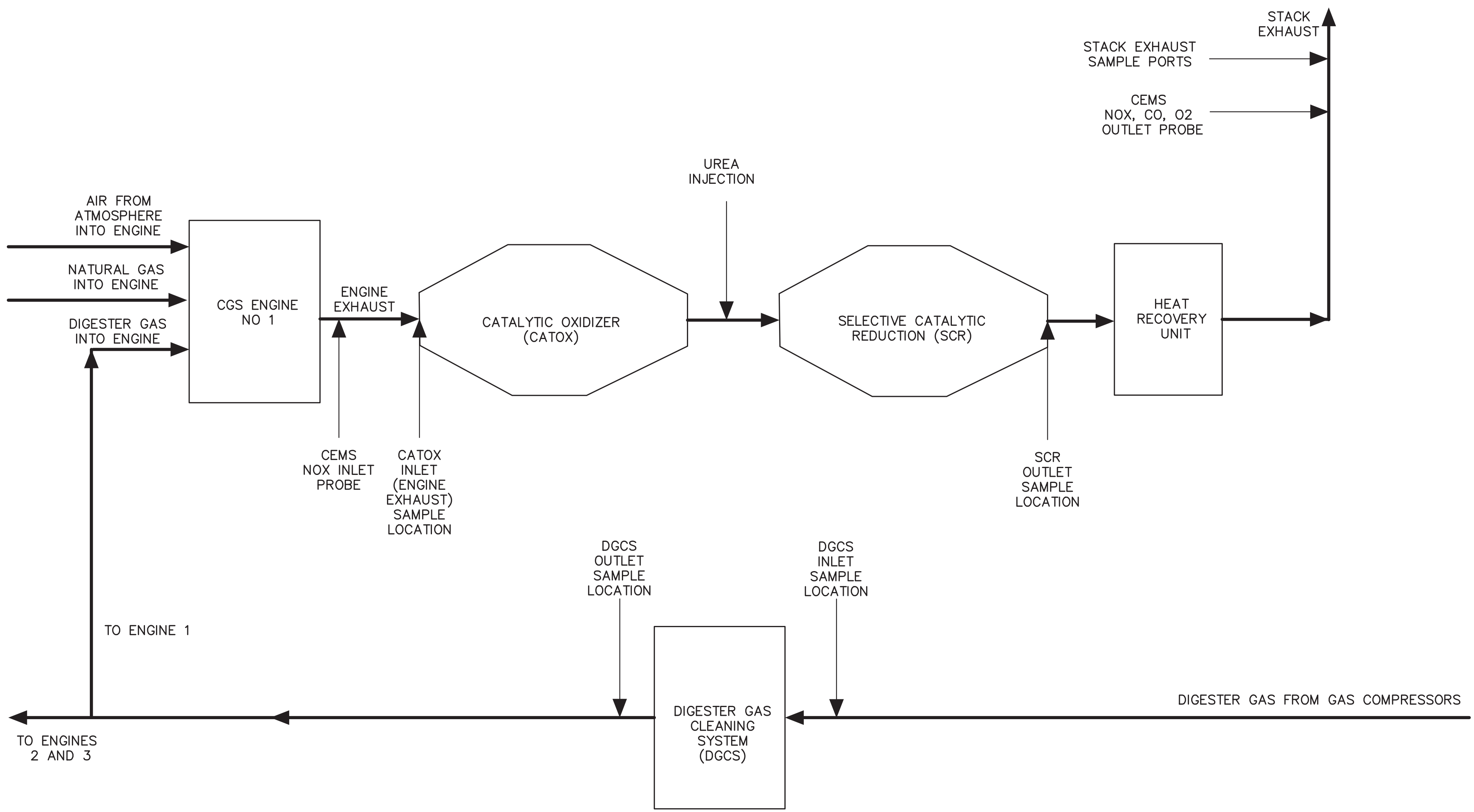
Charles Tupac

Charles Tupac, P.E.
A.Q.A.C. Supervisor
Refinery and Waste Management Permitting

CDT: GCR
cc: Mohan Nagavedu, AQMD
A/N 497717 folder

APPENDIX A-2:

Schematic of Project Set-up and Process and Instrumentation Diagrams



MALCOLM PIRNIE

REVISIONS

NO.	BY	DATE	REMARKS
1	DS	3/1/2010	SAMPLE LOCATIONS

DES DS
DWN DS
CKD KL

ORANGE COUNTY SANITATION DISTRICT
J-79 AIR QUALITY IMPROVEMENTS – PLANT NO 1 ENGINE 1

PILOT TEST EMISSION CONTROL SYSTEM

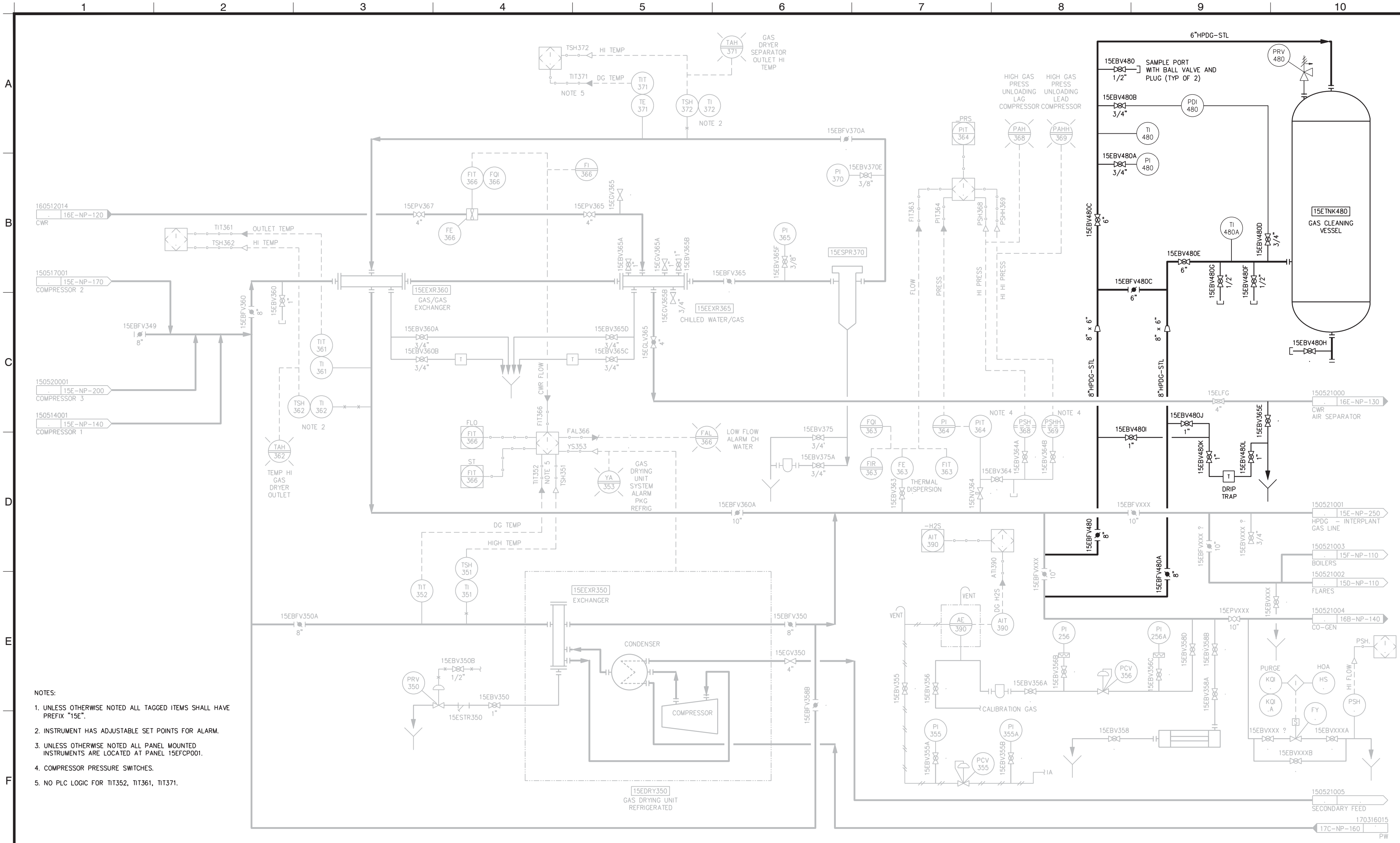
SCHEMATIC OF PILOT STUDY SET-UP

COPYRIGHT © MALCOLM PIRNIE, INC.

DATE MAY 2011

SHEET 1 OF 1

CAD REF. NO.



NOTES:

1. UNLESS OTHERWISE NOTED ALL TAGGED ITEMS SHALL HAVE PREFIX "15E".
2. INSTRUMENT HAS ADJUSTABLE SET POINTS FOR ALARM.
3. UNLESS OTHERWISE NOTED ALL PANEL MOUNTED INSTRUMENTS ARE LOCATED AT PANEL 15EFCP001.
4. COMPRESSOR PRESSURE SWITCHES.
5. NO PLC LOGIC FOR TIT352, TIT361, TIT371.

DWG: I:\ACAD\PROJ\J-79\Instr\PID DWG\15E-NP-210-15E-NP-210.dwg USER: Zomorodi
DATE: Mar 23, 2011 9:11am XREFS: OCSD-PID-DBDR

MARK	DESCRIPTION	DATE	APPR.

DESIGNED BY: ZOMORODI, S. - 1/11
DRAWN BY: RIVAS, A - 1/11
CHECKED BY: NIU, E - 1/11

LINE IS 2 INCHES AT FULL SIZE (IF NOT 2"-SCALE ACCORDINGLY)

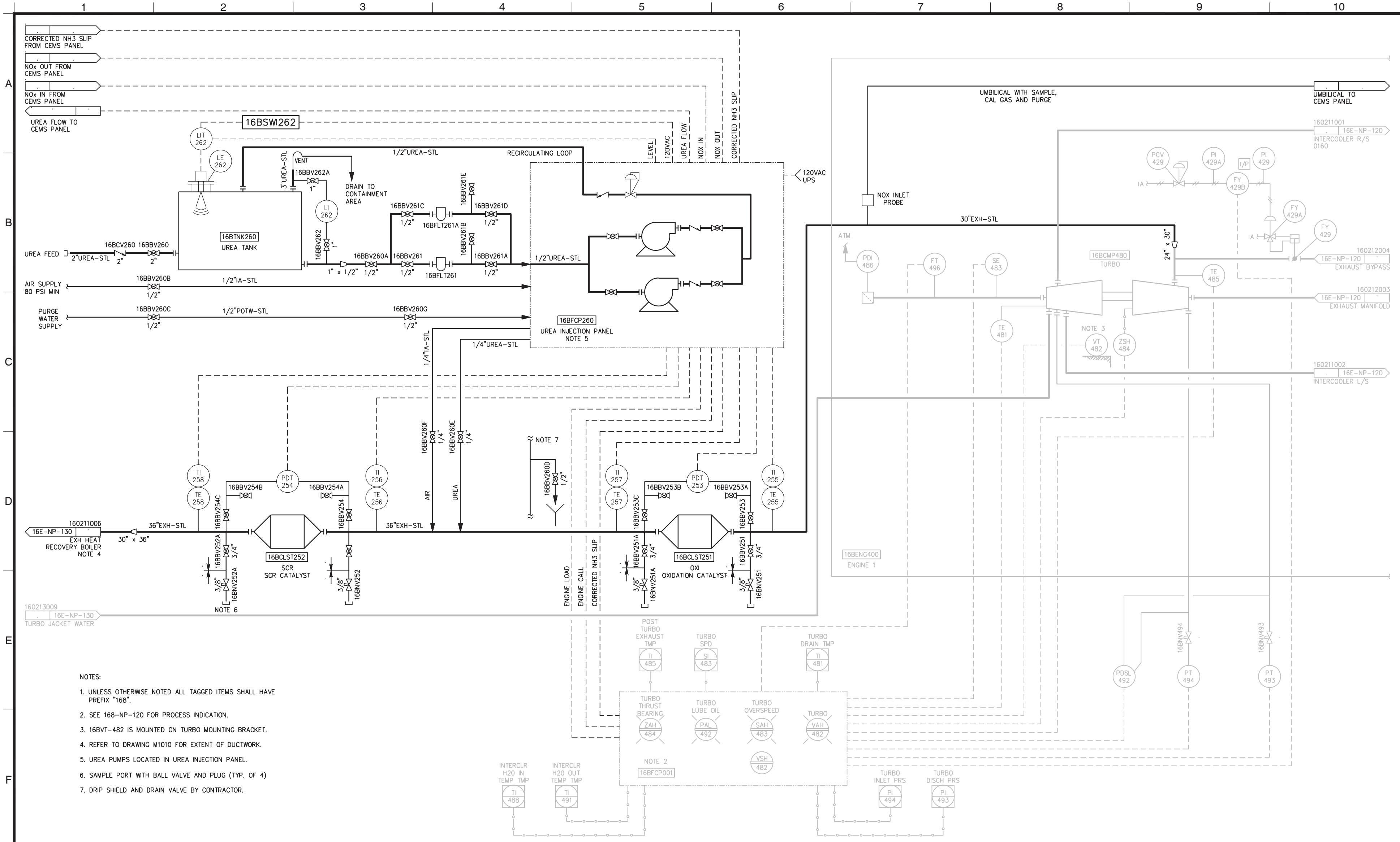
MALCOLM PIRNIE

ORANGE COUNTY SANITATION DISTRICT

PLANT NO.1-PILOT TEST-SCR/CATALYTIC OXIDIZER AND GAS CLEANING SYSTEMS

PROCESS & INSTRUMENTATION DIAGRAM
DIGESTER GAS FACILITIES
GAS DRYING UNIT

PLC NO. 15GCOMP
PROJECT NO. J-79
DRAWING NO. 15E-NP-210
19 OF 20



NOTES:

1. UNLESS OTHERWISE NOTED ALL TAGGED ITEMS SHALL HAVE PREFIX "168".
2. SEE 168-NP-120 FOR PROCESS INDICATION.
3. 16BVT-482 IS MOUNTED ON TURBO MOUNTING BRACKET.
4. REFER TO DRAWING M1010 FOR EXTENT OF DUCTWORK.
5. UREA PUMPS LOCATED IN UREA INJECTION PANEL.
6. SAMPLE PORT WITH BALL VALVE AND PLUG (TYP. OF 4)
7. DRIP SHIELD AND DRAIN VALVE BY CONTRACTOR.

DWG: I:\ACAD\PROJ\J-79\Instr\PID DWG\16B-NP-110-16B-NP-110.dwg USER: Zomorodi
DATE: Mar 23, 2011 9:11am XREFS: OCSD-PID-DBDR

MARK	DESCRIPTION	DATE	APPR.

DESIGNED BY: ZOMORODI, S. - 1/11
DRAWN BY: RIVAS, A. - 1/11
CHECKED BY: last, First - Date

LINE IS 2 INCHES AT FULL SIZE
(IF NOT 2"-SCALE ACCORDINGLY)

MALCOLM PIRNIE

ORANGE COUNTY SANITATION DISTRICT

PLANT NO.1-PILOT TEST-SCR/CATALYTIC OXIDIZER AND GAS CLEANING SYSTEMS

PROCESS & INSTRUMENTATION DIAGRAM
ENGINE AND EXHAUST FLOW
WITH SCR/OXI CAT

PLC NO. XX
PROJECT NO. J-79
DRAWING NO. 16B-NP-110
20 OF 20

APPENDIX A-3:

Technical Memorandum:
Comparison of Digester Gas Sampling Method for Speciated Siloxanes

Technical Memorandum

Date: July 13, 2011

To: File

From: Kit Liang, Malcolm Pirnie, WHI; Daniel Stepner, Malcolm Pirnie, WHI

Re: OCSD Cat Ox/SCR Pilot Study: Comparison of Digester Gas Sampling Method for Speciated Siloxanes

Project No.: 0788-187

Project Background

The Orange County Sanitation District (OCSD) requested pilot testing of a catalytic oxidizer/selective catalytic reduction (Cat Ox/SCR) system for controlling air toxics and priority pollutants from the Central Generation Systems (CGS) engines to meet February 2008 South Coast Air Quality Management District (SCAQMD) amendments to Rule 1110.2. The amendments to Rule 1110.2 included changes to the existing limits of 36 ppm to 11 ppm of oxides of nitrogen (NOx), 250 ppm to 30 ppm of volatile organic compounds (VOCs), and 2000 to 250 ppm of carbon monoxide (CO) at 15% O_2. The Cat Ox/SCR system reduces NOx, CO and VOC (i.e., formaldehyde, acrolein, etc.) emissions from IC engine exhaust.

The pilot testing project took place at Plant No. 1 on Engine No. 1 and included the installation of a Cat Ox/SCR system on the engine exhaust. This technology has been proven effective for controlling NOx, CO, and VOCs from combustion units burning natural gas. However, fouling or rapid performance degradation of the catalytic oxidizers has been an issue for engines burning digester gas. Typically, digester gas fuel contains contaminants such as volatile methyl-siloxanes and sulfurous compounds that tend to foul the catalytic oxidizers. Therefore, Malcolm Pirnie proposed a scope of work for a pilot test to verify the performance of the Cat Ox/SCR system with a digester gas cleaning system (DGCS). Based on the pilot testing performed at Plant No. 2 Engine No. 3 in 2007, the DGCS proved successful in removing contaminants such as siloxanes and hydrogen sulfide from the digester gas such that the catalyst performance is comparable to that of an internal combustion (IC) engine operating on natural gas.

Identification of Digester Gas Sampling Methods

The purpose of the digester gas cleaning system is to remove siloxanes and any potential contaminants, such as hydrogen sulfides in the digester gas, that can potentially foul or reduce the performance of the Cat Ox/SCR system. There are two sampling methods that are commonly used for measuring siloxanes: gas chromatography-mass spectrometry (GC/MS) or wet chemistry method. Digester gas analyzed using GC/MS can be collected using either Tedlar® bags or SUMMA canisters. The wet chemistry method requires samples to be collected using methanol impingers over a two to four hour sampling period, and then sent to a lab for analysis. After discussions with several certified laboratories, and review of several published papers, samples collected using Tedlar®, SUMMA canister or methanol impingers each has advantages and disadvantages based on the speciated siloxanes in the digester gas. However, collection of the samples using Tedlar® bags provides the most flexibility for minimum sampling time and equipment required.

As part of the Monitoring Test Procedure, the initial performance testing of the gas cleaning system collected samples using Tedlar® bags, SUMMA canister and methanol impinger methods at the digester gas inlet location during the same day and compared the analytical results to determine the most appropriate method for monitoring media breakthrough. The initial performance testing was performed by Malcolm Pirnie, except where noted. The following information was collected for the digester gas cleaning system test:

- Tedlar® bag collection at the DGCS inlet – Malcolm Pirnie collected and sent samples to a certified laboratory to test for speciated siloxanes, speciated VOCs using TO-15, total reduced sulfide using TO-15 and overall gas components and quality (%CH_4, %CO_2, %N_2, heating value) using EPA Method 3C.
- SUMMA canister collection at the DGCS inlet – Malcolm Pirnie collected and sent samples to a certified laboratory to test for speciated siloxanes, speciated VOCs using TO-15, total reduced sulfide using ASTM D-5504, and overall gas components and quality (%CH_4, %CO_2, %N_2, heating value) using ASTM D-1946.
- Wet chemistry method at the DGCS inlet – Engine 1 was operated for five hours at actual operating conditions with the digester gas cleaning system for performance testing. The performance test was performed for a continuous period of at least five hours (1 hour for stabilization and 4 hours for testing). During the test, individual measurements of inlet total siloxane, D4, D5, hexamethyl-disiloxane, octamethyltrisiloxane and any other siloxane compounds identifiable according to the test method was monitored and recorded.

Information obtained from the initial performance testing was used to select the most appropriate sampling method for the determining breakthrough and change-out.

Summary of Results

On March 16, 2010, digester gas was collected at the Plant 1 DGCS using the three sampling methods described above. Table 1 shows a summary of sampling results.

Table 1
Summary Comparison of Sampling Methods

OCSD Plant 1	Total Siloxane (ppbv)
Tedlar® – Inlet	3,584
SUMMA Canister – Inlet	546
Methanol Impinger – Inlet	1,457

Selection of the Sampling Method

The primary focus of the digester gas testing is to analyze for siloxane compounds. These compounds are most likely to foul the catalytic oxidizer catalyst. Of the three testing methods, the Tedlar® bag method resulted in the highest concentration of siloxanes. Siloxanes can be lost if a sample degrades. It is believed that the Tedlar® bag method provides a conservative estimate of siloxanes in the gas sample. The Tedlar® bag method also requires the least set-up and sampling time as well as the least equipment required. Although these were not the main criteria for selecting the sampling methods, they are benefits to using this method. When breakthrough of the carbon media is suspected, it is important to take a gas sample quickly to minimize potential fouling of the catalyst or downtime of the engine.

Based on the data presented above, the Tedlar® bag collection method was selected. Tedlar® bags provided the highest reported concentration of siloxanes and also provided the flexibility to test for VOCs and sulfurous compounds.

Conclusion

On March 16, 2010, digester gas was sampled at the inlet of the Plant 1 DGCS using three different methods: Tedlar® bags, SUMMA canisters, and methanol impingers. The gas samples collected using Tedlar® bags and SUMMA canisters were analyzed using GC/MS and the gas sample collected using methanol impingers was analyzed using the wet chemistry method. As shown in the summary of the results in Table 1, the Tedlar® bag sampling method detected the highest level of total siloxane. In addition, the Tedlar® bag sampling method provides the most flexibility of what compounds could be tested for and the minimum sampling time and equipment required. Based on these criteria, the Tedlar® bag method was chosen as the sampling method for future digester gas sampling.

APPENDIX A-4:

Technical Memorandum:
OCSD Catalytic Oxidizer/SCR Pilot Study:
SCR Urea Injection Mapping

MALCOLM PIRNIE

Technical Memorandum

Date: July 13, 2011

To: File

From: Kit Liang, Malcolm Pirnie, WHI; Daniel Stepner, Malcolm Pirnie, WHI

Re: OCSD Cat Ox/SCR Pilot Study: Urea Injection Mapping

Project No.: 0788-187

Project Background

To meet the South Coast Air Quality Management District (SCAQMD) Rule 1110.2 limit for oxides of nitrogen (NOx), the Orange County Sanitation District (OCSD) installed a selective catalytic reduction (SCR) system with urea injection was installed in the internal combustion (IC) engine exhaust duct after a catalytic oxidizer (Cat Ox) (both systems supplied by Johnson Matthey) on Engine 1 at Plant 1. Under Amended Rule 1110.2, NOx exhaust levels have a lower limit of 11 ppmv for biogas-fueled engines effective July 30, 2011. The SCR system was designed to remove NOx through a chemical reaction between the NOx in the engine exhaust and ammonia (provided by urea spray injected into the exhaust gas stream upstream of the SCR) on the surface of the SCR catalyst. The urea injection rate is selected ("mapped") based on engine load and outlet NOx concentration (related to the blend of digester gas and natural gas supplement used by the engines at Plant 1). This memorandum outlines the methodology developed to control the urea injection rate.

SCR Urea Control System

The function of the SCR control system is to balance urea injection rate to reduce NOx exhaust concentration without emitting excess ammonia in the post-control exhaust gas. The excess ammonia that passes through the SCR catalyst unreacted is, known as "ammonia slip." Ammonia slip occurs when too much ammonia, or in this case urea, is injected into the exhaust stream, when the temperature of the gas is too low for the ammonia to react, or when the catalyst is degraded. The Research Permit for the pilot study has a maximum allowable ammonia slip of 10 ppm at the stack exhaust. In addition to the unwanted emissions of ammonia from the stack exhaust, excess ammonia in the system can potentially cause damage to the heat recovery boiler and other equipment downstream from the SCR catalyst.

The control system determines the correct rate of urea injection according to the engine load signal, and this urea injection rate versus *engine load map* is programmed into the control system. The load map during the pilot testing period included 16 set points, and was programmed during commissioning by the system vendor, Johnson Matthey. This controller was able to interpolate between the tested load values to generate an overall curve of urea injection rate versus engine load. Thus, as the engine is brought to a load, and as the engine load changes, the urea flow rate is adjusted by a flow control valve based on the monitored engine load.

In addition to the load map control, the injection system also uses a system of bias set points to more finely control, or "trim", the urea injection rate. The "NOx curve bias" is a percentage that can be input by the operator to increase or decrease the urea injection rate. This bias is typically set to 0%, but can be modified if engine operation is expected to change the NOx produced in the exhaust emissions. "NOx-add bias" increases the urea injection rate setting (in terms of gallon per hour, gph) based on the NOx outlet concentration recorded by the stack exhaust CEMS analyzer. When the NOx outlet concentration reaches the level set by the control system, the urea injection rate will increase by the selected bias set point. Conversely, "NOx-subtract bias" decreases the urea injection rate in the same manner based on the NOx outlet concentration.

As the engine ran under varying loads during the load mapping procedure, Johnson Matthey measured NOx with a portable chemiluminescent analyzer, and ammonia slip with Draeger® tubes at the SCR catalyst outlet. The purpose of this was to develop a urea injection versus engine load map that met NOx and ammonia slip emissions requirements.

The initial load mapping performed by Johnson Matthey on April 1, 2010 is provided below in Table 1 and in Figure 1. The solid line in Figure 1 represents the set points for urea injection based on engine load. The dashed line represents the urea injection rate with the upper NOx-add bias that increases urea injection based on the NOx outlet emissions. Note that the bias is set for a lower and upper value of NOx outlet concentration. In the case of the April 1, 2010 set points, when the NOx outlet concentration reached the NOx lower add bias concentration (8 ppm), urea injection would increase by an additional 0.50 gph. If the NOx outlet concentration continued to increase and reached the NOx upper add bias concentration (10 ppm), the urea injection would increase by an additional 0.90 ppm).

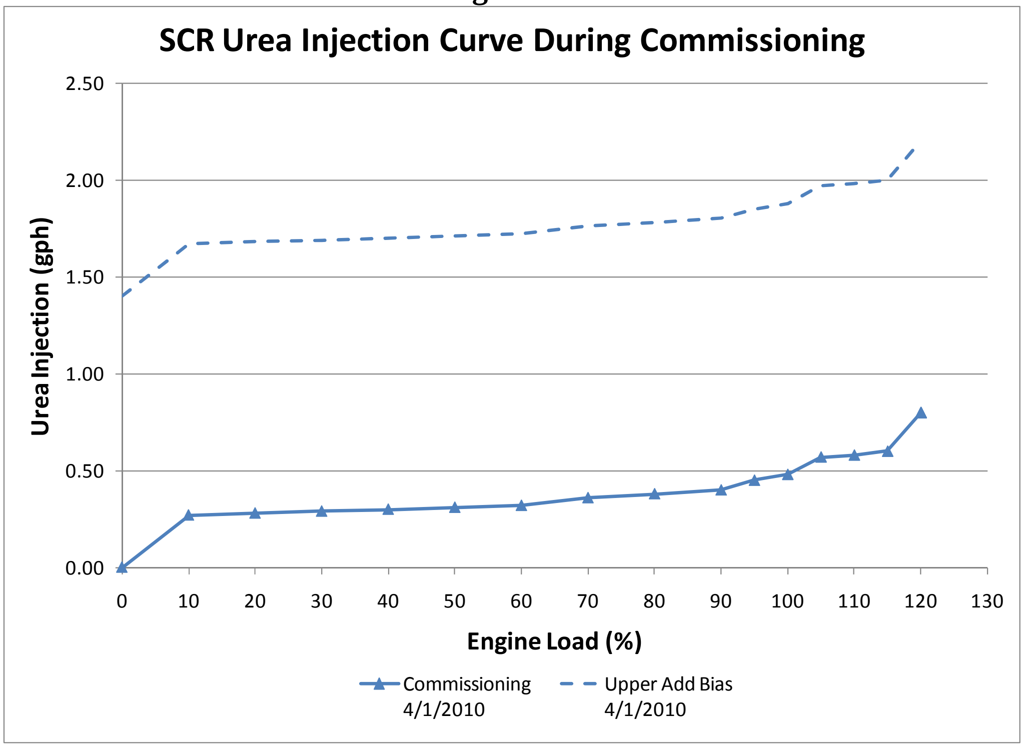
For the pilot testing period, a NOx-subtract bias was not set. A NOx-subtract bias would be used if the OCSD desired to keep the NOx outlet concentration above a threshold level. This could be set if there was a concern that urea would be over injected at low NOx outlet concentrations, causing ammonia slip issues. In the case of the pilot test, there was no desired lower NOx limit and no observed ammonia slip issues.

Table 1:

SCR Urea Injection Set Points at Commissioning (April 1, 2010)

Set Point	Engine Load (%)	Urea Injection Rate (gph)
1	0	0.00
2	10	0.27
3	20	0.28
4	30	0.29
5	40	0.30
6	50	0.31
7	60	0.32
8	70	0.36
9	80	0.38
10	90	0.40
11	95	0.45
12	100	0.48
13	105	0.57
14	110	0.58
15	115	0.60
16	120	0.80
NOx Bias Set Point	**NOx Outlet Concentration (ppmv)**	**Bias (gph)**
NOx curve bias	-	0%
NOx lower add bias	8	0.50
NOx upper add bias	10	0.90
NOx lower subtract bias	0	0.00
NOx upper subtract bias	0	0.00

Figure 1:



Urea Injection Set Point Adjustments During the Pilot Testing

During the pilot testing, Johnson Matthey made adjustments to the urea injection set points to refine control of the NOx emissions. On May 13, 2010, the urea injection NOx-add bias set points were decreased. The original NOx-add biases increased the urea injection rates by 0.50 and 0.90 gph when the NOx outlet concentrations hit 8 and 10 ppmv, respectively. Based on these set points, when the NOx outlet concentration reached the level set for the NOx-add bias, it was found that the system injected too much urea, so that the NOx outlet concentration was lowered too quickly, resulting in rapid fluctuations in the NOx outlet concentration. Therefore, the lower and upper NOx-add bias set points were set to 0.05 and 0.09 gph when the NOx outlet concentration reached 5 and 7 ppmv, respectively. With lower NOx-add bias set points, the maximum amount of urea injected (urea injection rate plus NO lower and upper add bias) was decreased. Therefore, the risk of not injecting enough urea to compensate for the NOx outlet concentration was increased. As a precautionary measure, the urea injection rate versus engine load set points were also increased slightly.

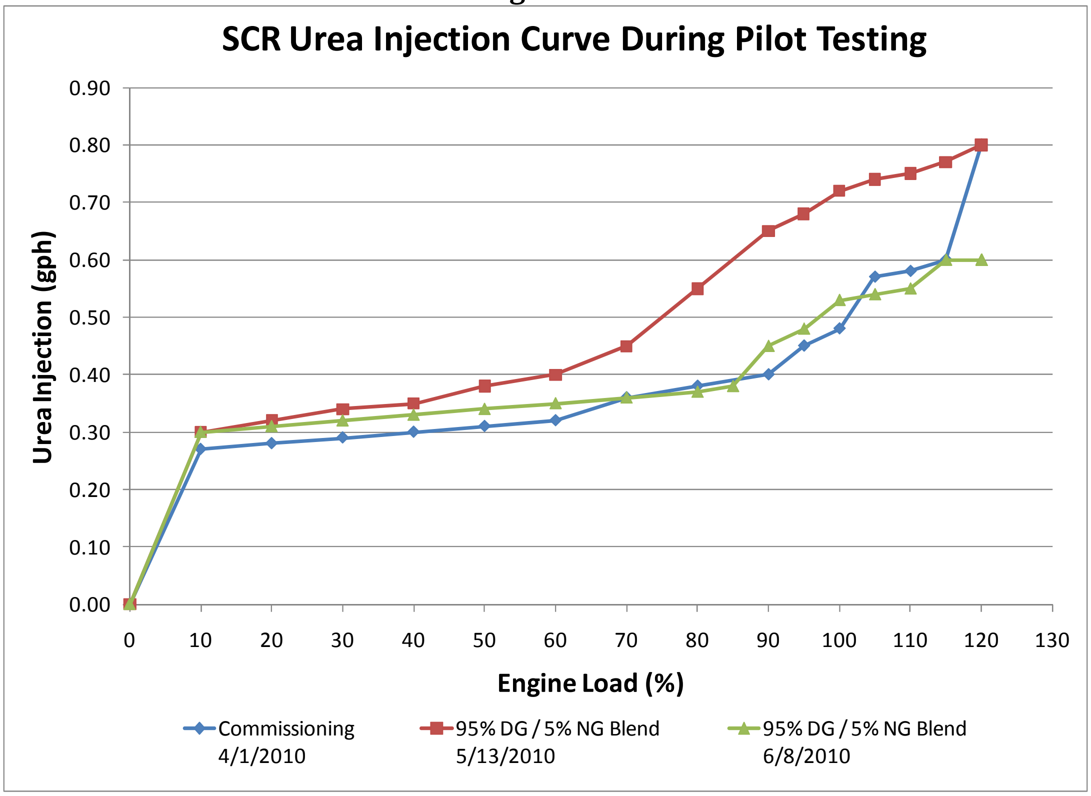
On June 8, 2010, the urea injection set points were readjusted. At the request of OCSD, the urea injection rate versus engine load set points were decreased to reduce possible ammonia slip resulting from over-injection of urea. This was a potential concern because the Plant 1 Engine 1 operates primarily on a greater than 95% digester gas to natural gas fuel ratio. The original set points were set higher to allow for a higher percentage of natural gas in the fuel, which in turn creates a higher NOx concentration in the engine exhaust. One additional set point was added at an engine load of 85% to further refine the engine load range. The set points programmed into the SCR control system on June 8, 2010 ran for the remaining pilot testing period through the end of March 2011. The effectiveness of these set points is discussed in the pilot testing report. A summary of the urea injection rate set points through the pilot testing period is provided in Table 2 and Figure 2.

Table 2:

SCR Urea Injection Set Points During the Pilot Testing

Load/Urea Injection Set Point	Commissioning 4/1/2010		5/13/2010		6/8/2010	
	Engine Load (%)	Urea Injection (gph)	Engine Load (%)	Urea Injection (gph)	Engine Load (%)	Urea Injection (gph)
1	0	0.00	0	0.00	0	0.00
2	10	0.27	10	0.30	10	0.30
3	20	0.28	20	0.32	20	0.31
4	30	0.29	30	0.34	30	0.32
5	40	0.30	40	0.35	40	0.33
6	50	0.31	50	0.38	50	0.34
7	60	0.32	60	0.40	60	0.35
8	70	0.36	70	0.45	70	0.36
9	80	0.38	80	0.55	80	0.37
10	90	0.40	90	0.65	85	0.38
11	95	0.45	95	0.68	90	0.45
12	100	0.48	100	0.72	95	0.48
13	105	0.57	105	0.74	100	0.53
14	110	0.58	110	0.75	105	0.54
15	115	0.60	115	0.77	110	0.55
16	120	0.80	120	0.80	115	0.60
17	-	-	-	-	120	0.60
NOx Bias Set Point	**NOx Outlet Concentration (ppmv)**	**Bias (gph)**	**NOx Outlet Concentration (ppmv)**	**Bias (gph)**	**NOx Outlet Concentration (ppmv)**	**Bias (gph)**
NOx curve bias	-	0%	-	0%	-	0%
NOx lower add bias	8	0.50	5	0.05	5	0.05
NOx upper add bias	10	0.90	7	0.09	7	0.09
NOx lower subtract bias	0	0.00	0	0.00	0	0.00
NOx upper subtract bias	0	0.00	0	0.00	0	0.00

Figure 2:



Limitations of the Urea Injection Mapping

Based on previous source testing data, the NOx concentration in the exhaust gas is higher when combusting natural gas than when combusting digester gas at a given load; therefore, there is a potential for variation in the NOx concentration at the inlet to the SCR system at a given load due to the varying fuel blend in biogas-fueled engines. Since the urea injection rate can only be established based on engine load and outlet NOx concentration, and not inlet NOx concentration, it is difficult to maintain a targeted NOx limit at the stack exhaust using this type of SCR system for fuel blend engines..

Conclusions and Recommendations

The urea injection set points were originally set during system commissioning on April 1, 2010 and were later readjusted on May 13, 2010 to refine NOx reduction in the engine exhaust gas. The urea injection set points were readjusted for a final time during the pilot test on June 8, 2010 for analysis of the SCR system.

Attachment:
Johnson Matthey Commissioning Report, June 1, 2010

Commissioning Report

Johnson Matthey
Catalysts

Date: 6/1/2010

Malcolm Pirnie / Orange County Sanitation District
Oxidation Catalyst and SCR Emission Control System
System Location: Orange County, CA

Prepared for:
Daniel Stepner and Kit Liang
Malcolm Pirnie

Written by:
Ben Tatum
Sr. Project Engineer
Johnson Matthey - Stationary Emission Control (SEC)
400 Lapp Rd #200
Malvern, PA 19355

The SCR and Oxidation catalyst system at the Orange County Sanitation District is designed to control NOx, hydrocarbon, and CO emissions from a Cooper Model LSVB-12-SGC engine. The required reduction rates are shown in Table 1: Emissions Data (ppmVD @ 15% O_2). The reduction rates are guaranteed based on a 15 min average value per South Coast AQMD rule 1110.2.

Table 1: Emissions Data (ppmVD @ 15% O_2)

Exhaust Component	Catalyst Inlet (max)	Catalyst Outlet (max)*	Reduction Guaranteed
NOx	50 ppm	9 ppm	82.0%
VOC	120 ppm	25 ppm	79.2%
CO	800 ppm	100 ppm	87.5%
HCHO	60 ppm	9 ppm	85.0%
Ammonia Slip	---	10 ppm	---

The SCR system is designed to accommodate changes in the fuel usage of the LSVB-12-SGC engine. The fuel blend can range from 100% natural gas with 0% digester gas to 5% natural gas with 95% digester gas. Four engine load conditions were used for commissioning purposes to determine the necessary urea injection rates. The engine load values chosen were 60%, 80%, 100%, and 110% as this range includes the normal operating conditions of the engine. In addition to varying the engine load, the fuel ratio of natural gas to digester gas was set to one of three conditions to determine the necessary urea injection rates. The fuel ratio testing conditions starting with the most common include 5% natural gas with 95% digester gas, 50% natural gas with 50% digester gas, and 100% natural gas with 0% digester gas. Emission testing was performed for all of the resulting 12 conditions and recorded in Table 2: Emission Testing Results. The results show that the system successfully reduced CO and NOx emissions below the permit conditions while maintaining an NH3 slip of below 10 ppm.

Table 2: Emission Testing Results

SP	Gas Ratio	OCSD Engine Load %	JM & DL Engine Load %	Valve %	Urea Flow gph	CEMS NOX Corr 15%	Ecom NOX Corr 15%	NH3 Slip	CEMS CO Corr 15%	Ecom CO Corr 15%	Ecom Temp Post SCR	JM Temp Pre SCR	JM Temp Post SCR
1	50/50	110	100	63	0.63	6.7	8	0.5	8.8	6.9	746	755	756
2	50/50	100	95	63	0.63	6.7	8	0.5	10	8	759	762	773
3	50/50	80	72.5	58	0.4	3.8	6	0.2	9.4	7	775	800	786
4	50/50	60	59.1	57	0.34	4.4	4	0.1	8.9	7	761	820	796
5	100ng/0d	110	98.1	69	0.91	4.5	7	0	10.9	9	737	752	754
6	100ng/0d	100	92	67	0.76	4.5	6	0	11.4	9	749	757	761
7	100ng/0d	80	73.7	62	0.54	3.4	5	0	11.7	10	766	781	782
8	100ng/0d	60	58.1	58	0.38	3.6	5	0	9.9	8	755	807	784
9	5ng/95d	110	98.8	63	0.58	5.6	5	0	9.7	6	758	756	762
10	5ng/95d	100	95.5	63	0.57	3.1	4	0.1	8.6	7	779	776	787
11	5ng/95d	80	72.2	58	0.38	3.7	5	0	9.1	8	791	811	812
12	5ng/95d	60	60	55	0.33	1.2	1	0.1	9	8	783	830	815

A urea injection map was created based on the results of the testing outlined in Table 2. The urea injection map serves as the base or default urea injection rate at the corresponding engine load, see Table 3 – Load Map. To compensate for changing NOx concentrations due to fuel ratio fluctuations a bias value is added to or subtracted from the base urea set point. If the NOx concentration at the system outlet climbs to 7 ppm or higher an additional 0.05 gph of urea is injected to bring the NOx levels down. If the NOx concentration at the system outlet continues to rise to 9 ppm or higher an additional 0.09 gph of urea will be injected via the additional bias. The resulting amount of urea will be injected upstream of the SCR catalyst to properly control NOx across all fuel ratios.

Table 3: Load Map / Base Urea Set points and Bias

Engine Load %	Urea Set point (gal/min)	Initial High Bias 7 ppm NOx (gal/min)	Additional High Bias 9 ppm NOx (gal/min)	Initial Low Bias x ppm NOx (gal/min)	Additional Low Bias x ppm NOx (gal/min)
0	0	+0.05	+0.09	0	0
10	0.30	+0.05	+0.09	0	0
20	0.31	+0.05	+0.09	0	0
30	0.32	+0.05	+0.09	0	0
40	0.33	+0.05	+0.09	0	0
50	0.34	+0.05	+0.09	0	0
60	0.35	+0.05	+0.09	0	0
70	0.36	+0.05	+0.09	0	0
80	0.37	+0.05	+0.09	0	0
90	0.45	+0.05	+0.09	0	0
95	0.48	+0.05	+0.09	0	0
100	0.53	+0.05	+0.09	0	0
105	0.54	+0.05	+0.09	0	0
110	0.55	+0.05	+0.09	0	0
115	0.60	+0.05	+0.09	0	0
120	0.60	+0.05	+0.09	0	0

The load map urea set points were determined based on the most common operating condition, which is a high concentration of digester gas (approximately 95% digester gas and 5% natural gas). It was determined during testing that adding natural gas to the fuel blend increased the NOx concentration in the exhaust stream. For this reason, the baseline urea set points coincide with the 95% digester gas and 5% natural gas fuel ratio condition which is the most common and requires the least amount of urea injection. The low bias was disabled for this application because the base urea set points correspond to the minimum urea flow requirements.

Some of the challenges of this control system include the 80 second delay between the time the exhaust gas concentrations change the moment the corresponding NOx concentration signal is received from the CEMS. This lagging indication of NOx concentration, which is used by the control system to determine if additional urea should be injected via the bias, causes an oscillation in the injection rate when the engine is running at high natural gas concentrations. At the lower and more common natural gas concentrations the system is more stable. These oscillations alone are not enough to bring the system out of compliance because the performance is based on a 15 minute average. The system is capable of being tuned to have an acceptable 15 minute average performance over all operating conditions. The second challenge is the fluctuation of the engine load signal. The engine load signal fluctuates very rapidly (a couple times per second) in a range of plus or minus 10%. The urea injection cabinet uses this signal to control the base urea injection set point. This engine load signal fluctuation causes an inherent fluctuation in the base urea injection rate although it is dampened somewhat by a PID loop.

The following is a table including all SCR system set points at the time of commissioning, see Table 4: System Set points. These set points are for informational purposes and should not be changed without the approval of Johnson Matthey.

Table 4: System Set Points

Component Description

Urea Heat Control system:	JM P&ID Reference	Set Point	Initiates Purge	Description
Control SP	TT-0301	40*F	No	Urea heater activates 5 DegF below this setpoint and de-activates 5 DegF above this setpoint
Temp Low SP	TT-0301	30*F	No	Alarms if this temperature is met indicating Urea heater circuit failure
System Time Delays:				
Air/Water Purge Time Delay	SV-0103	15 sec.	No	Timer for water purge prior to standard air purge
Engine Time Delay	CP-1001	100 sec.	No	Times out any alarms upon startup until system is fully operational
Kick-Start Timer	CV-0501	45 sec.	No	Opens Control Valve CV-0501 to 100% upon injection to fill feed line
Purge Time Delay	FS-1501	45 sec.	No	Timer to initiate redundant pump
Heater SP Time Delay	TT-0301	NA	No	Time delay to initiate urea heater
Fill Rate Time Delay	NA	NA	No	Time delay to initiate transfer pump
Flow Alarm Time Delay	FT-0401	4.5sec.	Yes	Time delay to initiate low flow alarm
System Operation:				
Air Pressure Main	PR-0602	100 psig	No	System air pressure main
Air Pressure Switch SP	PS-1601	30 psig	Yes	System purge and alarms when air pressure drops below this setpoint
Air Pressure to Injection Module	PR-0603	30 psig	No	Injection Module operational pressure
Cat Pre-Temp High AL	TT-0302	900F	No	Alarms if this temperature is met
Injection Temp SP	TT-0302	600F	No	Turns on injection at 10 DegF above this sp and turns off 10 Degf below this setpoint
Load/Urea SP	CP-1001	Startup	No	Load to Urea setpoint set during startup
Low Load SP	ELS-1901	10%	Yes	Urea will not be injected below this load
Load Deadband	ELS-1901	0%	Yes	Urea pump activates 5% above low load setpoint and de-activates 5% below setpoint
Low Tank Level	LT-1201	10%	Yes	Alarms below this setpoint, injection will not occur to prevent dry pump
Low Urea Flow	FT-0401	0.1	Yes	Alarms if urea flow during injection drops below this setpoint
Reagent Supply Pressure	PR-0601	100 psig	No	Urea supply pressure
Stop Air SP	NA	300 sec	No	Injection Module purges for this amount of time after system shuts down.
Urea High PSI SP	PT-0201	160 psig	No	Alarms when urea pressure is above this setpoint
Urea Low Flow SP	FS-1501	0.10 gph	Yes*	Initiates redundant pump when below this setpoint
Urea Low PSI SP	PT-0201	20 psig	No	Alarms when urea pressure is below this setpoint
Post Urea PSI	PT-0202	-	No	This pressure sensor is for monitoring and diagnostical reference only.
CAT Diff PSI		5psig	No	Alarms when the differential pressure across the catalysts exceeds this value.
Load, Urea Setpoints Main:				
Flowmeter Max Scale	FT-0401	3.0 gph	No	Maximum Scale of Urea Flow Transmitter
Air/Water Purge Time Delay	SV-0103	15 sec.	No	Timer for water purge prior to standard air purge
Calibration Screen:				
Engine Load- mA in Max	ELS-1901	20	N/A	Max mA signal received from engine relative to load
Engine Load- mA in Min	ELS-1901	3.98	N/A	Min mA signal received from engine relative to load
Engine Load- Max Scale	ELS-1901	110	N/A	Load that correlates to receiving a 20mA signal
Engine Load- Min Scale	ELS-1901	0	N/A	Load that correlates to receiving a 4mA signal
Urea Scale	FT-0401	99.6	N/A	Utilized for scaling flow transmitter at initial commissioning
Tank Scale Upper	LT-1201	100	N/A	Utilized for scaling level transmitter at initial commissioning
Tank Scale Lower	LT-1201	19.9	N/A	Utilized for scaling level transmitter at initial commissioning
PID Screen:				
Proportional Setting- P	CV-0501	750	N/A	Proportional Setting for CV-0501
Integral Setting- I	CV-0501	0.025	N/A	Integral Setting for CV-0501

SP=Set Point
* Initiates Purge when second pump does not activate switch

APPENDIX B-1:

Fixed Gas Sampling Summary

Fixed Gas Sampling Summary
Plant 1 - Digester Gas Cleaning System

Collection Date	Lab	Collection Method	Carbon Dioxide		Methane		Nitrogen		Oxygen	
			Inlet	**Outlet**	**Inlet**	**Outlet**	**Inlet**	**Outlet**	**Inlet**	**Outlet**
			(%)	**(%)**	**(%)**	**(%)**	**(%)**	**(%)**	**(%)**	**(%)**
3/16/2010	Centek	Tedlar Bag	33.4	32.4	55.2	54.9	1.1	1.7	0.3	0.5
4/7/2010	Centek	Tedlar Bag	27.0	27.6	53.7	62.5	1.6	1.7	0.6	0.8
4/29/2010	Centek	Tedlar Bag	28.5	31.4	62.6	59.5	2.0	1.7	0.5	0.5
5/19/2010	Centek (1)	Tedlar Bag	19.1	24.6	44.4	55.3	27.0	13.2	7.1	3.3
5/27/2010	Centek	Tedlar Bag	31.4	31.0	54.0	54.3	4.0	1.1	1.2	0.5
6/11/2010	Centek	Tedlar Bag	25.5	23.1	56.3	45.0	1.4	1.5	0.5	0.5
6/29/2010	Centek (2)	Tedlar Bag	40.1	34.5	58.3	48.4	4.0	16.0	1.1	4.3
8/12/2010	AccuLabs, Inc. (3)	Summa Canister	0.3	0.3	0.5	0.5	77.5	77.9	21.3	20.5
8/12/2010	AtmAA Inc.	Tedlar Bag	36.6	36.4	61.0	60.9	1.0	1.2	0.3	0.3
8/19/2010	AccuLabs, Inc. (4)	Tedlar Bag	31.2	15.7	63.9	32.3	1.9	45.7	0.5	5.4
8/19/2010	AccuLabs, Inc. (4)	Summa Canister	31.7	25.8	65.8	60.4	0.8	10.8	0.1	0.7
9/1/2010	AtmAA Inc.	Tedlar Bag	35.0	35.7	60.4	60.6	2.5	1.9	0.5	0.4
9/15/2010	AtmAA Inc.	Tedlar Bag	36.6	36.6	60.5	60.6	1.3	1.6	0.2	0.3
9/20/2010	AtmAA Inc.	Tedlar Bag	36.2	36.4	60.8	60.7	1.2	1.2	0.3	0.3
11/4/2010	AtmAA Inc.	Tedlar Bag	35.9	N/A	59.9	N/A	2.6	N/A	0.6	N/A
1/12/2011	AtmAA Inc.	Tedlar Bag	34.0	N/A	59.0	N/A	5.1	N/A	1.4	N/A
2/9/2011	AtmAA Inc.	Tedlar Bag	37.7	37.2	60.4	60.7	0.9	1.1	0.1	0.1
2/24/2011	AtmAA Inc.	Tedlar Bag	36.6	N/A	60.1	N/A	1.9	N/A	0.2	N/A
Minimum			**25.5**	**23.1**	**53.7**	**45.0**	**0.9**	**1.1**	**0.1**	**0.1**
Maximum			**40.1**	**37.2**	**62.6**	**62.5**	**5.1**	**1.9**	**1.4**	**0.8**
Average			**33.9**	**32.8**	**58.7**	**58.0**	**2.2**	**1.5**	**0.6**	**0.4**

Notes:

(1) Inlet and outlet sample results from 5/19/10 are not accurate due to an error in collection, indicated by high nitrogen composition (>5%), and are not included in the minimum, maximum and average.

(2) Outlet sample results from 6/29/10 are not accurate due to an error in collection, indicated by high nitrogen composition (>5%), and are not included in the minimum, maximum and average.

(3) Inlet and outlet sample results from AccuLabs on 8/12/10 are not accurate due to an error in collection, indicated by high nitrogen composition (>5%), and are not included in the minimum, maximum and average.

(4) Sample results from 8/19/10 are not consistent with sample results from other laboratories and are concluded to be erroneous and not included in the minimum, maximum and average.

(5) N/A indicates not applicable because the compound was not analyzed for.

APPENDIX B-2:

Total Reduced Sulfide Summary

Total Reduced Sulfide Summary
Plant 1 - Digester Gas Cleaning System

Collection Date	Lab (1)	Collection Method	Hydrogen Sulfide				Carbonyl Sulfide				Methyl Mercaptan				Ethyl Mercaptan			
			Inlet		Outlet		Inlet		Outlet		Inlet		Outlet		Inlet		Outlet	
			Rpt Lmt (ppbv)	Amt (ppbv)	Rpt Lmt (ppbv)	Amt (ppbv)	Rpt Lmt (ppbv)	Amt (ppbv)	Rpt Lmt (ppbv)	Amt (ppbv)	Rpt Lmt (ppbv)	Amt (ppbv)	Rpt Lmt (ppbv)	Amt (ppbv)	Rpt Lmt (ppbv)	Amt (ppbv)	Rpt Lmt (ppbv)	Amt (ppbv)
4/21/2010	OCSD	AQMD 307-91	1,000	25,700	25	ND	6	20	6	ND	12	70	12	ND	19	225	19	ND
5/11/2010	OCSD	AQMD 307-91	2,500	31,700	25	263	6	20	6	8	12	53	12	ND	19	263	19	ND
6/8/2010	OCSD	AQMD 307-91	630	27,970	63	2,162	5	16	5	ND	3	49	3	ND	4	272	4	ND
6/22/2010	OCSD	AQMD 307-91	630	21,620	6	ND	5	14	5	ND	3	54	3	ND	4	301	4	ND
7/7/2010	OCSD	AQMD 307-91	630	28,570	6	ND	5	13	5	ND	3	57	3	ND	4	265	4	ND
7/21/2010	OCSD	AQMD 307-91	630	24,870	6	ND	5	10	5	ND	3	48	3	ND	4	272	4	ND
8/3/2010	OCSD	AQMD 307-91	630	27,450	6	ND	5	19	5	12	3	58	3	ND	4	293	4	ND
8/12/2010	OCSD	AQMD 307-91	630	28,190	6	ND	5	22	5	18	3	72	3	ND	4	304	4	ND
8/12/2010	AccuLabs, Inc. (2)	Summa Canister	5	<MDL	5	<MDL	2	<MDL	2	<MDL	2	<MDL	2	<MDL	2	<MDL	2	<MDL
8/12/2010	AtmAA Inc.	Tedlar Bag	500	30,700	200	<MDL	200	<MDL	200	<MDL	200	<MDL	200	<MDL	200	<MDL	200	<MDL
8/19/2010	AccuLabs, Inc. (3)	Tedlar Bag	100	14,600	10	<MDL	5	13	5	<MDL	20	181	5	<MDL	20	470	5	<MDL
8/19/2010	AccuLabs, Inc. (3)	Summa Canister	100	14,100	10	<MDL	5	13	5	<MDL	20	191	5	<MDL	20	478	5	<MDL
9/1/2010	OCSD	AQMD 307-91	630	14,690	6	ND	5	28	5	15	3	81	3	ND	4	301	4	ND
9/14/2010	OCSD	AQMD 307-91	630	23,010	6	545	5	17	5	17	3	62	3	ND	4	258	4	ND
1/25/2011	OCSD	AQMD 307-91	630	28,540	6	ND	5	28	5	16	3	61	3	ND	4	189	4	ND
2/9/2011	OCSD	AQMD 307-91	630	31,870	6	1,755	5	21	5	18	3	79	3	ND	4	210	4	ND
2/23/2011	OCSD	AQMD 307-91	630	24,460	6	ND	5	15	5	ND	3	58	3	ND	4	205	4	ND
Minimum			**N/A**	**14,690**	**N/A**	**263**	**N/A**	**10**	**N/A**	**8**	**N/A**	**48**	**N/A**	**ND**	**N/A**	**189**	**N/A**	**ND**
Maximum			**N/A**	**31,870**	**N/A**	**2,162**	**N/A**	**28**	**N/A**	**18**	**N/A**	**81**	**N/A**	**ND**	**N/A**	**304**	**N/A**	**ND**
Average			**N/A**	**26,381**	**N/A**	**1,181**	**N/A**	**19**	**N/A**	**15**	**N/A**	**62**	**N/A**	**ND**	**N/A**	**258**	**N/A**	**ND**

Notes:

(1) Hydrogen sulfide results from Centek are above the operating range of the instrument and appear to be erroneous. Centek sample results are not included in the analysis of this pilot testing program.

(2) Inlet and outlet sample results from AccuLabs on 8/12/10 are not accurate due to an error in collection, indicated by high nitrogen composition (>5%), and are not included in the minimum, maximum and average.

(3) Sample results from 8/19/10 are not consistent with sample results from other laboratories and are concluded to be erroneous and not included in the minimum, maximum and average.

(4) N/A indicates not applicable or that the compound was not analyzed for.

(5) ND indicates non-detect.

(6) <MDL indicates that the result, if any, was less than the method detection limit.

Total Reduced Sulfide Summary
Plant 1 - Digester Gas Cleaning System

Collection Date	Lab (1)	Collection Method	Dimethyl Sulfide				Carbon Disulfide				n-Propyl Thiol				iso-Propyl Thiol			
			Inlet		Outlet		Inlet		Outlet		Inlet		Outlet		Inlet		Outlet	
			Rpt Lmt (ppbv)	Amt (ppbv)	Rpt Lmt (ppbv)	Amt (ppbv)	Rpt Lmt (ppbv)	Amt (ppbv)	Rpt Lmt (ppbv)	Amt (ppbv)	Rpt Lmt (ppbv)	Amt (ppbv)	Rpt Lmt (ppbv)	Amt (ppbv)	Rpt Lmt (ppbv)	Amt (ppbv)	Rpt Lmt (ppbv)	Amt (ppbv)
4/21/2010	OCSD	AQMD 307-91	18	ND	18	ND	13	ND	13	ND	21	584	21	ND	30	310	30	ND
5/11/2010	OCSD	AQMD 307-91	18	ND	18	ND	13	ND	13	ND	21	630	21	ND	30	360	30	ND
6/8/2010	OCSD	AQMD 307-91	5	8	5	10	3	4	3	3	320	536	3	ND	3	341	3	4
6/22/2010	OCSD	AQMD 307-91	5	6	5	ND	3	ND	3	ND	3	679	3	ND	3	406	3	ND
7/7/2010	OCSD	AQMD 307-91	5	12	5	ND	3	ND	3	ND	3	625	3	ND	3	381	3	ND
7/21/2010	OCSD	AQMD 307-91	5	8	5	12	3	ND	3	4	3	593	3	ND	3	373	3	ND
8/3/2010	OCSD	AQMD 307-91	5	13	5	12	3	ND	3	6	3	622	3	ND	3	401	3	ND
8/12/2010	OCSD	AQMD 307-91	5	17	5	20	3	ND	3	7	3	649	3	ND	3	416	3	ND
8/12/2010	AccuLabs, Inc. (2)	Summa Canister	2	15	2	11	2	5	2	4	2	<MDL	2	<MDL	2	<MDL	2	<MDL
8/12/2010	AtmAA Inc.	Tedlar Bag	200	<MDL	200	<MDL	200	<MDL	200	<MDL	320	<MDL	200	<MDL	250	<MDL	200	<MDL
8/19/2010	AccuLabs, Inc. (3)	Tedlar Bag	5	10	5	8	5	<MDL	5	<MDL	50	1,180	5	<MDL	5	<MDL	5	<MDL
8/19/2010	AccuLabs, Inc. (3)	Summa Canister	5	10	5	9	5	<MDL	5	2	50	1,190	5	<MDL	5	<MDL	5	<MDL
9/1/2010	OCSD	AQMD 307-91	5	13	5	18	3	9	3	12	3	565	3	ND	3	416	3	ND
9/14/2010	OCSD	AQMD 307-91	5	15	5	18	3	ND	3	7	3	631	3	ND	3	341	3	ND
1/25/2011	OCSD	AQMD 307-91	5	8	5	11	3	5	3	8	3	454	3	ND	3	214	3	ND
2/9/2011	OCSD	AQMD 307-91	5	14	5	ND	3	ND	3	6	3	514	3	ND	3	242	3	ND
2/23/2011	OCSD	AQMD 307-91	5	13	5	ND	3	ND	3	ND	3	476	3	ND	3	268	3	ND
Minimum			**N/A**	**6**	**N/A**	**10**	**N/A**	**4**	**N/A**	**3**	**N/A**	**454**	**N/A**	**ND**	**N/A**	**214**	**N/A**	**4**
Maximum			**N/A**	**17**	**N/A**	**20**	**N/A**	**9**	**N/A**	**12**	**N/A**	**679**	**N/A**	**ND**	**N/A**	**416**	**N/A**	**4**
Average			**N/A**	**12**	**N/A**	**14**	**N/A**	**6**	**N/A**	**7**	**N/A**	**581**	**N/A**	**ND**	**N/A**	**344**	**N/A**	**4**

Total Reduced Sulfide Summary
Plant 1 - Digester Gas Cleaning System

Collection Date	Lab (1)	Collection Method	Dimethyl Disulfide				Isopropyl Mercaptan				n-Propyl Mercaptan			
			Inlet		Outlet		Inlet		Outlet		Inlet		Outlet	
			Rpt Lmt (ppbv)	Amt (ppbv)	Rpt Lmt (ppbv)	Amt (ppbv)	Rpt Lmt (ppbv)	Amt (ppbv)	Rpt Lmt (ppbv)	Amt (ppbv)	Rpt Lmt (ppbv)	Amt (ppbv)	Rpt Lmt (ppbv)	Amt (ppbv)
4/21/2010	OCSD	AQMD 307-91	30	ND	30	ND	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
5/11/2010	OCSD	AQMD 307-91	30	ND	30	ND	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
6/8/2010	OCSD	AQMD 307-91	4	ND	4	ND	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
6/22/2010	OCSD	AQMD 307-91	4	ND	4	ND	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
7/7/2010	OCSD	AQMD 307-91	4	ND	4	ND	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
7/21/2010	OCSD	AQMD 307-91	4	ND	4	ND	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
8/3/2010	OCSD	AQMD 307-91	4	ND	4	ND	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
8/12/2010	OCSD	AQMD 307-91	4	ND	4	ND	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
8/12/2010	AccuLabs, Inc. (2)	Summa Canister	5	<MDL	5	<MDL	5	<2	5	<2	5	<2	5	<2
8/12/2010	AtmAA Inc.	Tedlar Bag	200	<MDL	200	<MDL	0.2	250	0.2	<MDL	0.2	320	0.2	<MDL
8/19/2010	AccuLabs, Inc. (3)	Tedlar Bag	5	<MDL	5	<MDL	5	<2	5	<2	50	1,180	5	<2
8/19/2010	AccuLabs, Inc. (3)	Summa Canister	5	<MDL	5	<MDL	5	<2	5	<2	50	1,190	5	<2
9/1/2010	OCSD	AQMD 307-91	4	ND	4	ND	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
9/14/2010	OCSD	AQMD 307-91	4	ND	4	ND	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
1/25/2011	OCSD	AQMD 307-91	4	ND	4	ND	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2/9/2011	OCSD	AQMD 307-91	4	ND	4	ND	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2/23/2011	OCSD	AQMD 307-91	4	ND	4	ND	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Minimum			**N/A**	**ND**	**N/A**	**ND**	**N/A**	**250**	**N/A**	**ND**	**N/A**	**320**	**N/A**	**ND**
Maximum			**N/A**	**ND**	**N/A**	**ND**	**N/A**	**250**	**N/A**	**ND**	**N/A**	**320**	**N/A**	**ND**
Average			**N/A**	**ND**	**N/A**	**ND**	**N/A**	**250**	**N/A**	**ND**	**N/A**	**320**	**N/A**	**ND**

APPENDIX B-3:

Speciated Siloxane Sampling Detailed Summary

Siloxane Sampling Summary
Plant 1 - Digester Gas Cleaning System

Collection Date	Lab	Collection Method	Hexamethyldisiloxane (L2)				Hexamethylcyclotrisiloxane (D3)				Octamethyltrisiloxane (L3)				Octamethylcyclotetrasiloxane (D4)			
			Inlet		Outlet		Inlet		Outlet		Inlet		Outlet		Inlet		Outlet	
			Rpt Lmt (ppbv)	Amt (ppbv)	Rpt Lmt (ppbv)	Amt (ppbv)	Rpt Lmt (ppbv)	Amt (ppbv)	Rpt Lmt (ppbv)	Amt (ppbv)	Rpt Lmt (ppbv)	Amt (ppbv)	Rpt Lmt (ppbv)	Amt (ppbv)	Rpt Lmt (ppbv)	Amt (ppbv)	Rpt Lmt (ppbv)	Amt (ppbv)
3/16/2010	Centek	Tedlar Bag	20	ND	20	ND	20	10	20	ND	20	12	20	ND	20	600	20	ND
4/7/2010	Centek	Tedlar Bag	20	ND	10	ND	20	9.7	10	ND	20	11	10	ND	20	840	10	ND
4/29/2010	Centek	Tedlar Bag	50	ND	10	ND	50	ND	10	ND	50	10	10	ND	50	1600	10	ND
5/19/2010	Centek (1)	Tedlar Bag	20	ND	10	ND	20	15	10	ND	20	17	10	ND	20	810	10	7.6
5/27/2010	Centek	Tedlar Bag	20	ND	10	8.4	20	13	10	ND	20	17	10	0.1	20	1300	10	5.2
5/27/2010	Centek	Methanol Impinger	20	N/A	10	ND	20	N/A	10	ND	20	N/A	10	ND	20	369	10	ND
6/11/2010	Centek	Tedlar Bag	20	ND	10	7.4	20	12	10	12	20	15	10	ND	20	660	10	200
6/29/2010	Centek (2)	Tedlar Bag	20	ND	10	ND	20	17	10	ND	20	19	10	ND	20	620	10	ND
8/12/2010	AccuLabs (3)	Summa Canister	0.025	3.12	0.025	2.98	0.025	<0.01	0.025	<0.01	0.025	<0.01	0.025	<0.01	0.025	<0.01	0.025	<0.01
8/12/2010	AtmAA	Tedlar Bag	N/A	ND	N/A	ND	N/A	ND	N/A	ND	N/A	ND	N/A	ND	N/A	471	N/A	ND
8/19/2010	AccuLabs (4)	Tedlar Bag	0.025	1.61	0.025	0.26	0.025	4.84	0.025	0.03	0.025	4.97	0.025	ND	0.025	41.5	0.025	0.03
8/19/2010	AccuLabs (4)	Summa Canister	0.025	1.34	0.025	0.23	0.025	5.62	0.025	0.03	0.025	5.84	0.025	ND	0.025	43.1	0.025	0.03
9/1/2010	AtmAA	Tedlar Bag	60	<MDL	60	<MDL	60	<MDL	60	<MDL	60	<MDL	60	<MDL	60	510	60	<MDL
9/15/2010	AtmAA	Tedlar Bag	60	<MDL	60	<MDL	60	<MDL	60	<MDL	60	<MDL	60	<MDL	60	860	60	<MDL
9/20/2010	AtmAA	Tedlar Bag	60	<MDL	60	<MDL	60	<MDL	60	<MDL	60	<MDL	60	<MDL	60	864	60	<MDL
11/4/2010	AtmAA	Tedlar Bag	60	<MDL	N/A	N/A	60	<MDL	N/A	N/A	60	<MDL	N/A	N/A	60	597	N/A	N/A
1/12/2011	AtmAA	Tedlar Bag	60	<MDL	N/A	N/A	60	<MDL	N/A	N/A	60	<MDL	N/A	N/A	60	409	N/A	N/A
2/9/2011	AtmAA	Tedlar Bag	60	<MDL	60	<MDL	60	<MDL	60	<MDL	60	<MDL	60	<MDL	60	420	60	<MDL
2/24/2011	AtmAA	Tedlar Bag	60	<MDL	N/A	N/A	60	<MDL	N/A	N/A	60	<MDL	N/A	N/A	60	438	N/A	N/A
Minimum			**N/A**	**<MDL**	**N/A**	**7.4**	**N/A**	**9.7**	**N/A**	**12.0**	**N/A**	**10.0**	**N/A**	**0.1**	**N/A**	**369**	**N/A**	**5.2**
Maximum			**N/A**	**<MDL**	**N/A**	**8.4**	**N/A**	**17.0**	**N/A**	**12.0**	**N/A**	**19.0**	**N/A**	**0.1**	**N/A**	**1,600**	**N/A**	**200.0**
Average			**N/A**	**<MDL**	**N/A**	**7.9**	**N/A**	**12.3**	**N/A**	**12.0**	**N/A**	**14.0**	**N/A**	**0.1**	**N/A**	**704**	**N/A**	**102.6**

Notes:

(1) Inlet and outlet sample results from 5/19/10 are not accurate due to an error in collection, indicated by high nitrogen composition (>5%), and are not included in the minimum, maximum and average.

(2) Outlet sample results from 6/29/10 are not accurate due to an error in collection, indicated by high nitrogen composition (>5%), and are not included in the minimum, maximum and average.

(3) Inlet and outlet sample results from AccuLabs on 8/12/10 are not accurate due to an error in collection, indicated by high nitrogen composition (>5%), and are not included in the minimum, maximum and average.

(4) Sample results from 8/19/10 are not consistent with sample results from other laboratories and are concluded to be erroneous and not included in the minimum, maximum and average.

(5) N/A indicates not applicable or that the compound was not analyzed for.

(6) ND indicates non-detect.

(7) <MDL indicates that the result, if any, was less than the method detection limit.

Siloxane Sampling Summary
Plant 1 - Digester Gas Cleaning System

Collection Date	**Lab**	**Collection Method**	**Decamethyltetrasiloxane (L4)**				**Decamethylcyclopentasiloxane (D5)**				**Total Siloxane**	
			Inlet		**Outlet**		**Inlet**		**Outlet**		**Inlet**	**Outlet**
			Rpt Lmt (ppbv)	Amt (ppbv)	Rpt Lmt (ppbv)	Amt (ppbv)	Rpt Lmt (ppbv)	Amt (ppbv)	Rpt Lmt (ppbv)	Amt (ppbv)		
3/16/2010	Centek	Tedlar Bag	20	84	20	ND	20	2900	20	7.0	**3,584.0**	**<MDL**
4/7/2010	Centek	Tedlar Bag	20	170	10	ND	20	7500	10	8.8	**8,510.0**	**<MDL**
4/29/2010	Centek	Tedlar Bag	50	100	10	ND	50	14000	10	ND	**15,700.0**	**ND**
5/19/2010	Centek (1)	Tedlar Bag	20	83	10	ND	20	3500	10	ND	**4,393.0**	**<MDL**
5/27/2010	Centek	Tedlar Bag	20	73	10	0.22	20	1300	10	15	**2,673.0**	**15.0**
5/27/2010	Centek	Methanol Impinger	20	N/A	10	ND	20	2478	10	ND	**2,847.0**	**ND**
6/11/2010	Centek	Tedlar Bag	20	130	10	ND	20	7700	10	36	**8,490.0**	**248.0**
6/29/2010	Centek (2)	Tedlar Bag	20	170	10	ND	20	7900	10	39	**8,690.0**	**39.0**
8/12/2010	AccuLabs (3)	Summa Canister	0.025	<0.01	0.025	<0.01	0.025	<0.01	0.025	<0.01	**3.1**	**3.0**
8/12/2010	AtmAA	Tedlar Bag	N/A	ND	N/A	ND	N/A	3254	N/A	ND	**3,725.0**	**ND**
8/19/2010	AccuLabs (4)	Tedlar Bag	0.025	6.36	0.025	ND	0.03	860	0.03	ND	**919.3**	**0.3**
8/19/2010	AccuLabs (4)	Summa Canister	0.025	6.72	0.025	ND	0.1	908	0.025	ND	**970.6**	**0.3**
9/1/2010	AtmAA	Tedlar Bag	80	<MDL	80	<MDL	80	4058	80	<MDL	**4,568.0**	**<0.4**
9/15/2010	AtmAA	Tedlar Bag	80	<MDL	80	<MDL	80	3486	80	<MDL	**4,346.0**	**<0.4**
9/20/2010	AtmAA	Tedlar Bag	80	<MDL	80	<MDL	80	4862	80	<MDL	**5,726.0**	**<0.4**
11/4/2010	AtmAA	Tedlar Bag	80	<MDL	N/A	N/A	80	4632	N/A	N/A	**5,229.0**	**N/A**
1/12/2011	AtmAA	Tedlar Bag	80	<MDL	N/A	N/A	80	6140	N/A	N/A	**6,549.0**	**N/A**
2/9/2011	AtmAA	Tedlar Bag	80	<MDL	80	<MDL	80	4160	80	<MDL	**4,580.0**	**<MDL**
2/24/2011	AtmAA	Tedlar Bag	80	<MDL	N/A	N/A	80	6200	N/A	N/A	**6,638.0**	**N/A**
Minimum			**N/A**	**73**	**N/A**	**0.2**	**N/A**	**1,300**	**N/A**	**7.0**	**919**	**0.3**
Maximum			**N/A**	**170**	**N/A**	**0.2**	**N/A**	**14,000**	**N/A**	**36.0**	**15,700**	**248.0**
Average			**N/A**	**121**	**N/A**	**0.2**	**N/A**	**5,371**	**N/A**	**16.7**	**5,452**	**60.5**

APPENDIX B-4:

Volatile Organic Compound Summary

VOC Data Summary
Plant 1 - Digester Gas Cleaning System

Analyte	3/16/2010				3/16/2010		4/7/2010				4/29/2010			
	Centek				AccuLabs (Summa Canister)		Centek				Centek			
	Inlet (ppbv)		Outlet (ppbv)		Inlet (ppbv)		Inlet (ppbv)		Outlet (ppbv)		Inlet (ppbv)		Outlet (ppbv)	
	Rpt Lmt	Amt	Rpt Lmt	Amt	Rpt Lmt	Amt	Rpt Lmt	Amt	Rpt Lmt	Amt	Rpt Lmt	Amt	Rpt Lmt	Amt
Acetone	40	ND	40	40	2.5	<2.5	40	ND	20	17	100	63	20	15
Benzene	20	13	20	ND	0.5	9.25	20	8.2	10	ND	50	10	10	ND
Carbon Disulfide	20	ND	20	ND	0.5	0.97	20	ND	10	3.4	50	ND	10	5
Chlorobenzene	20	ND	20	ND	0.5	<0.21	20	ND	10	ND	50	ND	10	ND
Cyclohexane	20	ND	20	ND	0.5	2.94	20	18	10	ND	50	22	10	ND
1,2-Dichlorobenzene	20	ND	20	ND	0.5	0.33	20	ND	10	ND	50	ND	10	ND
1,4-Dichlorobenzene	20	5	20	ND	0.5	12.6	20	ND	10	ND	50	28	10	ND
cis-1,2-Dichloroethene	20	35	20	4.3	0.5	30.6	20	23	10	ND	50	45	10	12
trans-1,2-Dichloroethene	20	ND	20	ND	0.5	<0.20	20	ND	10	ND	50	ND	10	ND
Ethanol	N/A	N/A	N/A	N/A	1.0	<0.37	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Ethyl Acetate	40	ND	40	ND	1.0	<0.45	40	ND	20	ND	100	ND	20	ND
Ethylbenzene	20	37	20	ND	0.5	33.4	20	44	10	ND	50	100	10	ND
4-Ethyltoluene	20	20	20	ND	0.5	14.7	20	21	10	ND	50	43	10	ND
Freon 11	20	ND	20	ND	N/A	N/A	20	ND	10	ND	50	ND	10	2.9
n-Heptane	20	73	20	ND	0.5	55.9	20	75	10	ND	50	100	10	ND
Hexane	20	ND	20	ND	0.5	80.2	20	88	10	ND	50	210	10	ND
Isopropyl Alcohol	20	ND	20	300	N/A	N/A	20	ND	10	30	50	ND	10	13
Methylene Chloride	20	7.7	20	ND	2.5	7.63	20	5.2	10	3.8	50	12	10	5.2
Methyl Isobutyl Ketone (MIBK)	40	ND	40	ND	2.0	<0.57	40	ND	20		100	ND	20	ND
2-Propanol (IPA)	N/A	N/A	N/A	N/A	1.0	4.05	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Propene	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Propylene	20	ND	20	ND	5.0	2140	20	ND	10	ND	50	ND	10	ND
Styrene	20	4.7	20	ND	0.5	5.65	20	4.2	10	ND	50	19	10	ND
Tetrachloroethene (PCE)	N/A	N/A	N/A	N/A	0.5	5.16	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Tetrachloroethylene	20	8.2	20	ND	N/A	N/A	20	ND	10	ND	50	ND	10	ND
Toluene	20	1200	20	ND	5.0	1350	20	1300	10	4.1	50	1600	10	ND
1,2,4-Trichlorobenzene	20	ND	20	ND	0.5	<0.26	20	ND	10	ND	50	ND	10	ND
Trichloroethene (TCE)	20	12	20	11	0.5	7.26	20	9.6	10	ND	50	14	10	ND
Trichloroethylene	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Trichlorofluoromethane(F-11)	N/A	N/A	N/A	N/A	2.0	2.36	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
1,2,4-Trimethylbenzene	20	76	20	ND	0.5	110	20	70	10	ND	50	240	10	ND
1,3,5-Trimethylbenzene	20	33	20	ND	0.5	38.5	20	30	10	ND	50	88	10	ND
2,2,4-Trimethylpentane	20	27	20	ND	N/A	N/A	20	66	10	ND	50	65	10	ND
Vinyl Chloride	20	ND	20	ND	0.5	2.39	20	ND	10	ND	50	ND	10	ND
m & p-Xylene	40	69	40	ND	1.0	76.8	40	76	20	ND	100	100	20	ND
o-Xylene	20	24	20	ND	0.5	27.9	20	26	10	ND	50	41	10	ND
Total VOCs	**N/A**	**1,594**	**N/A**	**340**	**N/A**	**4,019**	**N/A**	**1,819**	**N/A**	**30**	**N/A**	**2,403**	**N/A**	**25**

Notes:

(1) Inlet and outlet sample results from 5/19/10 are not accurate due to an error in collection, indicated by high nitrogen composition (>5%), and are not included in the minimum, maximum and average.

(2) Outlet sample results from 6/29/10 are not accurate due to an error in collection, indicated by high nitrogen composition (>5%), and are not included in the minimum, maximum and average.

(3) Inlet and outlet sample results from AccuLabs on 8/12/10 are not accurate due to an error in collection, indicated by high nitrogen composition (>5%), and are not included in the minimum, maximum and average.

(4) Sample results from 8/19/10 are not consistent with sample results from other laboratories and are concluded to be erroneous and not included in the minimum, maximum and average.

(5) N/A indicates not applicable or that the compound was not analyzed for.

(6) ND indicates non-detect.

(7) <MDL indicates that the result, if any, was less than the method detection limit.

VOC Data Summary
Plant 1 - Digester Gas Cleaning System

Analyte	5/11/2010				5/19/2010				5/25/2010				5/27/2010			
	OCSD				Centek (1)				OCSD				Centek			
	Inlet (ppbv)		Outlet (ppbv)		Inlet (ppbv)		Outlet (ppbv)		Inlet (ppbv)		Outlet (ppbv)		Inlet (ppbv)		Outlet (ppbv)	
	Rpt Lmt	Amt	Rpt Lmt	Amt	Rpt Lmt	Amt	Rpt Lmt	Amt	Rpt Lmt	Amt	Rpt Lmt	Amt	Rpt Lmt	Amt	Rpt Lmt	Amt
Acetone	4.300	7.24	4.640	7.01	40	ND	20	45	4.640	10.2	4.300	9.67	40	ND	20	ND
Benzene	3.900	9.53	4.210	ND	20	22	10	11	4.210	9.28	3.900	ND	20	9.8	10	4.1
Carbon Disulfide	6.280	ND	6.780	ND	20	9.8	10	21	6.780	ND	6.280	ND	20	ND	10	3.5
Chlorobenzene	3.780	4.57	4.080	ND	20	9.6	10	ND	4.080	5.85	3.780	ND	20	ND	10	ND
Cyclohexane	3.820	ND	4.130	ND	20	33	10	12	4.130	ND	3.820	ND	20	12	10	6.5
1,2-Dichlorobenzene	3.520	ND	3.810	ND	20	ND	10	ND	3.810	ND	3.520	ND	20	ND	10	ND
1,4-Dichlorobenzene	3.580	20.8	3.860	ND	20	47	10	ND	3.860	26.8	3.580	ND	20	5.3	10	ND
cis-1,2-Dichloroethene	3.080	37.7	3.320	17.1	20	360	10	54	3.320	103	3.080	72.4	20	80	10	63
trans-1,2-Dichloroethene	3.680	ND	3.970	ND	20	32	10	4.4	3.970	ND	3.680	3.71	20	ND	10	5.8
Ethanol	4.300	ND	4.640	ND	N/A	N/A	N/A	N/A	4.640	ND	4.300	ND	N/A	N/A	N/A	N/A
Ethyl Acetate	5.450	ND	5.890	ND	40	ND	20	ND	5.890	ND	5.450	ND	40	ND	20	4.3
Ethylbenzene	3.380	85.4	3.640	ND	20	250	10	2.6	3.640	141	3.380	ND	20	96	10	7.8
4-Ethyltoluene	3.000	59.3	3.240	ND	20	65	10	ND	3.240	51.1	3.000	ND	20	16	10	ND
Freon 11	N/A	N/A	N/A	N/A	20	ND	10	5.1	N/A	N/A	N/A	N/A	20	6.3	10	4.8
n-Heptane	3.080	83.8	3.320	ND	20	210	10	3	3.320	87.2	3.080	41.8	20	76	10	36
Hexane	3.620	37	3.920	ND	20	200	10	47	3.920	36.6	3.620	9.55	20	150	10	27
Isopropyl Alcohol	2.950	ND	3.190	ND	20	ND	10	27	3.190	ND	2.950	ND	20	ND	10	ND
Methylene Chloride	5.220	ND	5.640	ND	20	9	10	9.4	5.640	ND	5.220	ND	20	8.2	10	7.3
Methyl Isobutyl Ketone (MIBK)	2.950	ND	3.190	ND	40	ND	20	ND	3.190	ND	2.950	ND	40	ND	20	ND
2-Propanol (IPA)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Propene	44.600	3270	48.800	3480	N/A	N/A	N/A	N/A	49.300	3130	45.400	3470	N/A	N/A	N/A	N/A
Propylene	N/A	N/A	N/A	N/A	20	ND	10	ND	N/A	N/A	N/A	N/A	20	ND	10	ND
Styrene	2.080	7.92	2.240	ND	20	49	10	ND	2.240	24.7	2.080	ND	20	13	10	4.3
Tetrachloroethene (PCE)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Tetrachloroethylene	3.350	ND	3.620	ND	20	370	10	ND	3.620	ND	3.350	6.56	20	6	10	4.2
Toluene	23.600	1340	2.560	ND	20	2700	10	25	26.000	2010	23.900	1030	50	1200	20	360
1,2,4-Trichlorobenzene	2.600	ND	2.810	ND	20	ND	10	ND	2.810	ND	2.600	ND	20	ND	10	ND
Trichloroethene (TCE)	N/A	N/A	N/A	N/A	20	610	10	22	N/A	N/A	N/A	N/A	20	14	10	7.6
Trichloroethylene	3.520	9.67	3.810	ND	N/A	N/A	N/A	N/A	3.810	12.7	3.520	10.2	N/A	N/A	N/A	N/A
Trichlorofluoromethane(F-11)	7.120	ND	7.700	ND	N/A	N/A	N/A	N/A	7.700	ND	7.120	ND	N/A	N/A	N/A	N/A
1,2,4-Trimethylbenzene	3.300	178	3.560	ND	20	430	10	ND	3.560	188	3.300	ND	20	81	10	ND
1,3,5-Trimethylbenzene	4.100	77.1	4.430	ND	20	150	10	ND	4.430	76.2	4.100	ND	20	35	10	ND
2,2,4-Trimethylpentane	N/A	N/A	N/A	N/A	20	89	10	3.2	N/A	N/A	N/A	N/A	20	60	10	25
Vinyl Chloride	5.200	ND	5.620	ND	20	12	10	5.8	5.620	ND	5.200	6.81	20	ND	10	6.6
m & p-Xylene	4.220	103	4.560	ND	40	240	20	ND	4.560	88.5	4.220	ND	40	47	20	ND
o-Xylene	4.050	42.6	4.370	ND	20	91	10	ND	4.370	35.6	4.050	ND	20	20	10	ND
Total VOCs	**N/A**	**5,374**	**N/A**	**3,504**	**N/A**	**5,948**	**N/A**	**264**	**N/A**	**6,037**	**N/A**	**4,651**	**N/A**	**1,845**	**N/A**	**511**

VOC Data Summary
Plant 1 - Digester Gas Cleaning System

Analyte	6/8/2010				6/11/2010				6/29/2010				7/7/2010			
	OCSD				Centek				Centek (2)				OCSD			
	Inlet (ppbv)		Outlet (ppbv)		Inlet (ppbv)		Outlet (ppbv)		Inlet (ppbv)		Outlet (ppbv)		Inlet (ppbv)		Outlet (ppbv)	
	Rpt Lmt	Amt	Rpt Lmt	Amt	Rpt Lmt	Amt	Rpt Lmt	Amt	Rpt Lmt	Amt	Rpt Lmt	Amt	Rpt Lmt	Amt	Rpt Lmt	Amt
Acetone	4.470	ND	4.820	ND	40	ND	40	200	40	88	20	65	4.640	9.24	5.160	ND
Benzene	4.060	11	4.370	6.01	20	15	20	7.2	20	14	10	ND	4.210	7.34	4.680	ND
Carbon Disulfide	6.530	ND	7.030	ND	20	ND	20	5.8	20	ND	10	3.2	6.780	ND	7.530	ND
Chlorobenzene	3.930	ND	4.230	ND	20	5.9	20	ND	20	6.4	10	ND	4.080	ND	4.530	ND
Cyclohexane	3.980	ND	4.280	ND	20	ND	20	9.2	20	16	10	ND	4.130	ND	4.590	ND
1,2-Dichlorobenzene	3.670	ND	3.950	ND	20	ND	20	ND	20	ND	10	ND	3.810	ND	4.230	ND
1,4-Dichlorobenzene	3.720	19.2	4.000	ND	20	16	20	ND	20	17	10	ND	3.860	ND	4.290	ND
cis-1,2-Dichloroethene	3.200	37.6	3.440	59.6	20	42	20	55	20	44	10	ND	3.320	22.7	3.690	ND
trans-1,2-Dichloroethene	3.820	ND	4.120	ND	20	ND	20	ND	20	4.6	10	ND	3.970	ND	4.410	ND
Ethanol	4.470	ND	4.820	ND	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	4.640	ND	5.160	ND
Ethyl Acetate	5.670	ND	6.100	ND	40	ND	40	ND	40	ND	20	ND	5.890	ND	6.540	ND
Ethylbenzene	3.510	74.1	3.780	38.9	20	110	20	61	20	84	10	ND	3.640	62.4	4.050	ND
4-Ethyltoluene	3.120	68.6	3.360	ND	20	31	20	9	20	21	10	ND	3.240	28.8	3.600	ND
Freon 11	N/A	N/A	N/A	N/A	20	ND	20	5.9	20	5.2	10	3.5	N/A	N/A	N/A	N/A
n-Heptane	3.200	62.4	3.440	45.8	20	94	20	44	20	99	10	ND	3.320	79.1	3.690	ND
Hexane	3.770	33.7	4.060	26.6	20	130	20	35	20	160	10	3.2	3.920	35.6	4.350	ND
Isopropyl Alcohol	3.070	ND	3.300	ND	20	ND	20	ND	20	ND	10	ND	3.190	ND	3.540	ND
Methylene Chloride	5.430	ND	5.850	5.96	20	9.3	20	13	20	14	10	8.8	5.640	ND	6.270	6.38
Methyl Isobutyl Ketone (MIBK)	3.070	ND	3.300	ND	40	ND	40	ND	40	ND	20	ND	3.190	ND	3.540	ND
2-Propanol (IPA)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Propene	47.200	3630	49.900	4130	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	47.900	3270	53.800	3600
Propylene	N/A	N/A	N/A	N/A	20	ND	20	ND	20	ND	10	ND	N/A	N/A	N/A	N/A
Styrene	2.160	8.4	2.320	ND	20	23	20	6.2	20	15	10	2.6	2.240	7.18	2.490	ND
Tetrachloroethene (PCE)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Tetrachloroethylene	3.480	ND	3.750	11.5	20	21	20	7.5	20	13	10	ND	3.620	ND	4.020	ND
Toluene	24.900	3080	26.300	1400	20	3600	20	800	20	2000	10	3.7	25.300	2090	2.850	ND
1,2,4-Trichlorobenzene	2.700	ND	2.910	ND	20	ND	20	ND	20	9.2	10	ND	2.810	ND	3.120	ND
Trichloroethene (TCE)	N/A	N/A	N/A	N/A	20	28	20	16	20	17	10	ND	N/A	N/A	N/A	N/A
Trichloroethylene	3.670	6.24	3.950	12.3	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	3.810	7.14	4.230	ND
Trichlorofluoromethane(F-11)	7.410	ND	7.980	ND	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	7.700	ND	8.550	ND
1,2,4-Trimethylbenzene	3.430	117	3.700	ND	20	190	20	ND	20	120	10	ND	3.560	124	3.960	ND
1,3,5-Trimethylbenzene	4.260	38.4	4.590	ND	20	69	20	ND	20	44	10	ND	4.430	36.2	4.920	ND
2,2,4-Trimethylpentane	N/A	N/A	N/A	N/A	20	55	20	31	20	39	10	ND	N/A	N/A	N/A	N/A
Vinyl Chloride	5.410	ND	5.820	ND	20	ND	20	ND	20	ND	10	ND	5.620	ND	6.240	ND
m & p-Xylene	4.390	60.5	4.730	31.4	40	100	40	52	40	180	20	ND	4.560	111	5.070	7.90
o-Xylene	4.210	24.4	4.540	ND	20	42	20	10	20	64	10	ND	4.370	41.6	4.860	ND
Total VOCs	**N/A**	**7,272**	**N/A**	**5,768**	**N/A**	**4,535**	**N/A**	**1,278**	**N/A**	**2,943**	**N/A**	**65**	**N/A**	**5,932**	**N/A**	**3,614**

VOC Data Summary
Plant 1 - Digester Gas Cleaning System

Analyte	7/21/2010				8/3/2010				8/12/2010				8/12/2010			
	OCSD				OCSD				OCSD				AccuLabs, Inc. - Summa Canisters (3)			
	Inlet (ppbv)		Outlet (ppbv)		Inlet (ppbv)		Outlet (ppbv)		Inlet (ppbv)		Outlet (ppbv)		Inlet (ppbv)		Outlet (ppbv)	
	Rpt Lmt	Amt	Rpt Lmt	Amt	Rpt Lmt	Amt	Rpt Lmt	Amt	Rpt Lmt	Amt	Rpt Lmt	Amt	Rpt Lmt	Amt	Rpt Lmt	Amt
Acetone	4.300	6.97	4.820	12.7	4.640	17.7	4.990	13.8	4.820	10.7	4.640	13	N/A	N/A	N/A	N/A
Benzene	3.900	8.70	4.370	ND	4.210	10.9	4.520	ND	4.370	9.15	4.210	ND	N/A	N/A	N/A	N/A
Carbon Disulfide	6.280	ND	7.030	ND	7.280	ND	7.280	ND	7.030	ND	6.780	ND	N/A	N/A	N/A	N/A
Chlorobenzene	3.780	ND	4.230	ND	4.380	ND	4.380	ND	4.230	ND	4.080	ND	N/A	N/A	N/A	N/A
Cyclohexane	3.820	ND	4.280	ND	4.440	ND	4.440	ND	4.280	8.88	4.130	ND	N/A	N/A	N/A	N/A
1,2-Dichlorobenzene	3.520	ND	3.950	ND	4.090	ND	4.090	ND	3.950	ND	3.810	ND	N/A	N/A	N/A	N/A
1,4-Dichlorobenzene	3.580	ND	4.000	ND	4.150	ND	4.150	ND	4.000	ND	3.860	ND	N/A	N/A	N/A	N/A
cis-1,2-Dichloroethene	3.080	17.2	3.440	17.3	3.320	44.2	3.570	65.1	3.440	24.6	3.320	60.2	N/A	N/A	N/A	N/A
trans-1,2-Dichloroethene	3.680	ND	4.120	ND	4.260	ND	4.260	ND	4.120	ND	3.970	ND	N/A	N/A	N/A	N/A
Ethanol	4.300	ND	4.820	9.89	4.990	ND	4.990	5.52	4.820	ND	4.640	ND	N/A	N/A	N/A	N/A
Ethyl Acetate	5.450	ND	6.100	ND	6.320	ND	6.320	ND	6.100	ND	5.890	ND	N/A	N/A	N/A	N/A
Ethylbenzene	3.380	60.7	3.780	ND	3.640	50.2	3.920	4.07	3.780	52.8	3.640	ND	N/A	N/A	N/A	N/A
4-Ethyltoluene	3.000	34.2	3.360	ND	3.240	32.1	3.480	ND	3.360	26.3	3.240	ND	N/A	N/A	N/A	N/A
Freon 11	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
n-Heptane	3.080	84.1	3.440	ND	3.320	82.8	3.570	26.3	3.440	122	3.320	17.3	N/A	N/A	N/A	N/A
Hexane	3.620	40.5	4.060	13.8	3.920	48.4	4.200	21.4	4.060	65.1	3.920	26.8	N/A	N/A	N/A	N/A
Isopropyl Alcohol	2.950	ND	3.300	ND	3.420	ND	3.420	ND	3.300	ND	3.190	ND	N/A	N/A	N/A	N/A
Methylene Chloride	5.220	ND	5.850	9.52	5.640	5.87	6.060	ND	5.850	6.01	5.640	6.19	N/A	N/A	N/A	N/A
Methyl Isobutyl Ketone (MIBK)	2.950	ND	3.300	ND	3.420	ND	3.420	ND	3.300	ND	3.190	ND	N/A	N/A	N/A	N/A
2-Propanol (IPA)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Propene	45.200	3140	49.500	3540	48.100	3630	52.400	3590	50.400	3140	49.300	3600	N/A	N/A	N/A	N/A
Propylene	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Styrene	2.080	7.19	2.320	ND	2.240	4.95	2.410	ND	2.320	6.01	2.240	ND	N/A	N/A	N/A	N/A
Tetrachloroethene (PCE)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Tetrachloroethylene	3.350	ND	3.750	ND	3.620	26.3	3.890	ND	3.750	ND	3.620	ND	N/A	N/A	N/A	N/A
Toluene	23.800	2510	2.660	ND	25.400	2110	2.760	ND	26.600	2680	2.560	9.76	N/A	N/A	N/A	N/A
1,2,4-Trichlorobenzene	2.600	ND	2.910	ND	3.560	ND	3.020	ND	2.910	ND	2.810	ND	N/A	N/A	N/A	N/A
Trichloroethene (TCE)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Trichloroethylene	3.520	9.78	3.950	ND	3.810	22.9	4.090	5.67	3.950	12.8	3.810	5.21	N/A	N/A	N/A	N/A
Trichlorofluoromethane(F-11)	7.120	ND	7.980	ND	8.260	ND	8.260	ND	7.980	ND	7.700	ND	N/A	N/A	N/A	N/A
1,2,4-Trimethylbenzene	3.300	154	3.700	ND	3.560	121	3.830	ND	3.700	115	3.560	ND	N/A	N/A	N/A	N/A
1,3,5-Trimethylbenzene	4.100	45.8	4.590	ND	4.430	39.9	4.760	ND	4.590	39.6	4.430	ND	N/A	N/A	N/A	N/A
2,2,4-Trimethylpentane	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Vinyl Chloride	5.200	ND	5.820	ND	6.030	ND	6.030	ND	5.820	ND	5.620	ND	N/A	N/A	N/A	N/A
m & p-Xylene	4.220	110	4.730	ND	4.560	82.9	4.900	15.4	4.730	83.2	4.560	ND	N/A	N/A	N/A	N/A
o-Xylene	4.050	43.3	4.540	ND	4.370	33.4	4.700	ND	4.540	31.4	4.370	ND	N/A	N/A	N/A	N/A
Total VOCs	**N/A**	**6,272**	**N/A**	**3,593**	**N/A**	**6,364**	**N/A**	**3,747**	**N/A**	**6,434**	**N/A**	**3,738**	**N/A**	**N/A**	**N/A**	**N/A**

VOC Data Summary
Plant 1 - Digester Gas Cleaning System

Analyte	8/12/2010				8/19/2010				8/19/2010				9/1/2010			
	AtmAA Inc. - Tedlar Bags				AccuLabs, Inc. - Tedlar Bags (4)				AccuLabs, Inc. - Summa Canisters (4)				OCSD			
	Inlet (ppbv)		Outlet (ppbv)		Inlet (ppbv)		Outlet (ppbv)		Inlet (ppbv)		Outlet (ppbv)		Inlet (ppbv)		Outlet (ppbv)	
	Rpt Lmt	Amt	Rpt Lmt	Amt	Rpt Lmt	Amt	Rpt Lmt	Amt	Rpt Lmt	Amt	Rpt Lmt	Amt	Rpt Lmt	Amt	Rpt Lmt	Amt
Acetone	N/A	79	N/A	42.2	2.5	62	2.5	33.7	2.5	27.3	2.5	20.5	4.640	11	4.640	14.9
Benzene	N/A	15.70	N/A	7.83	0.5	14.80	0.5	3.72	0.5	15.20	0.5	3.4	4.210	7.75	4.210	7.55
Carbon Disulfide	8	ND	8	ND	0.5	1.21	0.5	3.13	0.5	1.16	0.5	3.91	6.780	ND	6.780	9.3
Chlorobenzene	8	ND	8	ND	0.5	ND	0.5	ND	0.5	ND	0.5	ND	4.080	ND	4.080	ND
Cyclohexane	8	ND	8	ND	0.5	7.61	0.5	ND	0.5	7.82	0.5	1.72	4.130	ND	4.130	ND
1,2-Dichlorobenzene	6	ND	6	ND	0.5	ND	0.5	ND	0.5	ND	0.5	ND	3.810	ND	3.810	ND
1,4-Dichlorobenzene	6	8.32	6	ND	0.5	4.47	0.5	ND	0.5	10.8	0.5	ND	3.860	17.9	3.860	ND
cis-1,2-Dichloroethene	N/A	34.1	N/A	66.9	0.5	45.2	0.5	44.2	0.5	47.3	0.5	44.7	3.320	47.3	3.320	70.3
trans-1,2-Dichloroethene	8	ND	8	ND	0.5	ND	0.5	ND	0.5	ND	0.5	ND	3.970	ND	3.970	ND
Ethanol	N/A	N/A	N/A	N/A	1.0	ND	1.0	ND	1.0	ND	1.0	ND	4.640	ND	4.640	ND
Ethyl Acetate	N/A	22.2	N/A	15.3	1.0	ND	1.0	ND	1.0	ND	1.0	ND	5.890	ND	5.890	ND
Ethylbenzene	8	52.4	8	ND	0.5	54.2	0.5	1.85	0.5	59.7	0.5	1.2	3.640	73.2	3.640	ND
4-Ethyltoluene	8	64.1	8	ND	0.5	11.5	0.5	ND	0.5	14.9	0.5	1.3	3.240	12.7	3.240	ND
Freon 11	N/A	ND	N/A	ND	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
n-Heptane	8	ND	8	36.2	0.5	95.1	0.5	10.1	0.5	91.1	0.5	9.21	3.320	85.3	3.320	9.94
Hexane	N/A	97.9	N/A	44	0.5	90.1	0.5	10.2	0.5	89.5	0.5	9.9	3.920	52.1	3.920	33.4
Isopropyl Alcohol	12	ND	12	ND	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	3.190	ND	3.190	ND
Methylene Chloride	8	ND	8	ND	2.5	14.4	2.5	6.54	2.5	12.1	2.5	6.26	5.640	ND	5.640	ND
Methyl Isobutyl Ketone (MIBK)	N/A	N/A	N/A	N/A	2.0	5.91	2.0	ND	2.0	5.82	2.0	ND	3.190	ND	3.190	ND
2-Propanol (IPA)	N/A	N/A	N/A	N/A	1.0	ND	1.0	ND	1.0	ND	1.0	ND	N/A	N/A	N/A	N/A
Propene	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	101.000	3320	47.900	3980
Propylene	N/A	N/A	N/A	N/A	5.0	2910	5.0	1620	5.0	2870	5.0	1510	N/A	N/A	N/A	N/A
Styrene	8	ND	8	ND	0.5	4.96	0.5	ND	0.5	6.9	0.5	ND	2.240	12.9	2.240	ND
Tetrachloroethene (PCE)	6	11	6	ND	0.5	8.32	0.5	0.95	0.5	8.97	0.5	0.86	N/A	N/A	N/A	N/A
Tetrachloroethylene	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	3.620	6.64	3.620	ND
Toluene	N/A	1630	N/A	18.6	5.0	1430	0.5	42.7	5.0	1570	0.5	40.4	53.400	7300	2.560	287
1,2,4-Trichlorobenzene	8	ND	8	ND	0.5	ND	0.5	ND	0.5	ND	0.5	ND	2.810	ND	3.560	ND
Trichloroethene (TCE)	N/A	16.3	N/A	8.38	0.5	16.6	0.5	3.72	0.5	18.1	0.5	3.37	N/A	N/A	N/A	N/A
Trichloroethylene	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	3.810	9.21	3.810	10.6
Trichlorofluoromethane(F-11)	N/A	N/A	N/A	N/A	2.0	4.6	2.0	1.23	2.0	4.11	2.0	3.66	7.700	ND	7.700	ND
1,2,4-Trimethylbenzene	8	70.2	8	ND	0.5	38.5	0.5	1.57	0.5	56.7	0.5	6.49	3.560	67.1	3.560	ND
1,3,5-Trimethylbenzene	8	33	8	ND	0.5	18.8	0.5	0.44	0.5	23.9	0.5	1.82	4.430	34	4.430	ND
2,2,4-Trimethylpentane	8	ND	8	ND	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Vinyl Chloride	6	ND	6	ND	0.5	2.19	0.5	2.43	0.5	2.97	0.5	2.28	5.620	ND	5.620	ND
m & p-Xylene	8	91.6	8	ND	1.0	117	1.0	4.07	1.0	134	1.0	5.28	4.560	54.6	4.560	ND
o-Xylene	8	33.4	8	ND	0.5	40.2	0.5	2.19	0.5	45.6	0.5	2.48	4.370	21.6	4.370	ND
Total VOCs	**N/A**	**2,259**	**N/A**	**239**	**N/A**	**4,998**	**N/A**	**1,791**	**N/A**	**5,124**	**N/A**	**1,679**	**N/A**	**11,133**	**N/A**	**4,423**

VOC Data Summary
Plant 1 - Digester Gas Cleaning System

Analyte	9/14/2010				1/13/2011				2/9/2011			
	OCSD				OCSD				OCSD			
	Inlet (ppbv)		Outlet (ppbv)		Inlet (ppbv)		Outlet (ppbv)		Inlet (ppbv)		Outlet (ppbv)	
	Rpt Lmt	Amt	Rpt Lmt	Amt	Rpt Lmt	Amt	Rpt Lmt	Amt	Rpt Lmt	Amt	Rpt Lmt	Amt
Acetone	4.820	7.29	4.640	14.2	4.820	19.6	4.990	15.2	4.820	8.69	4.640	ND
Benzene	4.370	10.40	4.210	23	4.370	12.10	4.520	5.57	4.370	11.40	4.210	ND
Carbon Disulfide	7.030	ND	6.780	7.22	7.030	ND	7.280	ND	7.030	ND	6.780	ND
Chlorobenzene	4.230	ND	4.080	ND	4.230	4.5	4.380	ND	4.230	ND	4.080	ND
Cyclohexane	4.280	4.91	4.130	9.71	4.280	ND	4.440	4.52	4.280	ND	4.130	ND
1,2-Dichlorobenzene	3.950	ND	3.810	ND	3.950	ND	4.090	ND	3.950	ND	3.810	ND
1,4-Dichlorobenzene	4.000	ND	3.860	ND	4.000	ND	4.150	ND	4.000	ND	3.860	ND
cis-1,2-Dichloroethene	3.440	41.2	3.320	82.3	3.440	35.5	3.570	61.1	3.440	31.8	3.320	29.1
trans-1,2-Dichloroethene	4.120	ND	3.970	ND	4.120	ND	4.260	ND	4.120	ND	3.970	ND
Ethanol	4.820	ND	4.640	ND	4.820	ND	4.990	ND	4.820	ND	5.720	ND
Ethyl Acetate	6.100	ND	5.890	ND	6.100	ND	6.320	ND	6.100	ND	5.890	ND
Ethylbenzene	3.780	92.7	3.640	13.2	3.700	58	3.920	ND	3.780	61.2	3.640	22.2
4-Ethyltoluene	3.360	23.2	3.240	ND	3.360	30.3	3.480	ND	3.360	23.6	3.240	ND
Freon 11	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
n-Heptane	3.440	106	3.320	86	3.440	63.9	3.570	46.6	3.440	57.8	3.320	10.9
Hexane	4.060	57.2	3.920	130	4.060	27	4.200	47.6	4.060	31.1	3.920	13.4
Isopropyl Alcohol	3.300	ND	3.190	ND	3.300	ND	3.420	ND	3.300	ND	3.190	ND
Methylene Chloride	5.850	ND	5.640	ND	5.850	11.6	6.060	16.3	5.850	9.32	5.640	8.19
Methyl Isobutyl Ketone (MIBK)	3.300	ND	3.190	ND	3.300	4.51	3.420	ND	3.300	4.38	3.190	ND
2-Propanol (IPA)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Propene	50.200	3730	48.800	4100	50.900	2410	51.500	2370	49.900	2820	48.400	2370
Propylene	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Styrene	2.320	9.27	2.240	ND	2.320	8.06	2.410	ND	2.320	6.83	2.240	ND
Tetrachloroethene (PCE)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Tetrachloroethylene	3.750	ND	3.620	ND	3.750	ND	3.890	ND	3.750	ND	3.620	ND
Toluene	26.500	2690	25.700	2860	26.900	1090	2.760	9.72	26.300	1900	25.600	377
1,2,4-Trichlorobenzene	2.910	ND	2.810	ND	2.910	ND	3.020	ND	2.910	ND	2.810	ND
Trichloroethene (TCE)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Trichloroethylene	3.950	8.06	3.810	26.5	3.950	21.4	4.090	9.21	3.950	9.34	3.910	5.18
Trichlorofluoromethane(F-11)	7.980	ND	7.700	ND	7.980	ND	8.260	ND	7.980	ND	7.700	ND
1,2,4-Trimethylbenzene	3.700	104	3.560	ND	3.700	99	3.830	ND	3.700	101	3.560	ND
1,3,5-Trimethylbenzene	4.590	38.3	3.240	ND	4.590	33.2	4.760	ND	4.590	33.2	4.430	ND
2,2,4-Trimethylpentane	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Vinyl Chloride	5.820	ND	5.620	ND	5.820	ND	6.030	ND	5.820	ND	5.620	ND
m & p-Xylene	4.730	159	4.560	ND	4.730	111	4.900	6.41	4.730	102	4.560	31.1
o-Xylene	4.540	57.8	4.370	ND	4.540	38	5.890	ND	4.540	34.1	4.370	ND
Total VOCs	**N/A**	**7,139**	**N/A**	**7,352**	**N/A**	**4,078**	**N/A**	**2592**	**N/A**	**5,246**	**N/A**	**2867**

APPENDIX B-5:

Speciated Siloxane and Hydrogen Sulfide Sampling Summary

Digester Gas Sampling Summary
Plant 1 - Digester Gas Cleaning System

Date of Sampling	Approximate Volume of Gas Treated (Million Cubic Feet)	Total Siloxane (ppmv)		H2S OCSD AQMD 307-91 (ppmv)		H2S OCSD Draeger Tube (ppmv)	
		Inlet	Outlet	Inlet	Outlet	Inlet	Outlet
3/16/2010	0.00	3.58	<MDL	N/A	N/A	N/A	N/A
4/7/2010	27.26	8.51	<MDL	N/A	N/A	N/A	N/A
4/21/2010	53.41	N/A	N/A	25.70	ND	26	ND
4/29/2010	68.93	15.70	ND	N/A	N/A	N/A	N/A
5/11/2010	91.86	N/A	N/A	31.70	0.263	31	ND
5/27/2010	122.58	2.67	0.015	N/A	N/A	N/A	N/A
6/8/2010	144.70	N/A	N/A	27.97	2.162	30	2
6/11/2010	146.46	8.49	0.248	N/A	N/A	N/A	N/A
6/12/2010	Carbon media changed.						
6/22/2010	18.44	N/A	N/A	21.62	ND	27	-
6/29/2010	32.70	8.69	N/A	N/A	N/A	N/A	N/A
7/7/2010	46.34	N/A	N/A	28.57	ND	25	N/A
7/21/2010	68.89	N/A	N/A	24.87	ND	25	N/A
8/3/2010	90.04	N/A	N/A	27.45	ND	25	N/A
8/12/2010	106.00	N/A	N/A	28.19	ND	26	N/A
8/12/2010	106.00	3.73	ND	N/A	N/A	N/A	N/A
9/1/2010	137.15	4.57	<MDL	N/A	N/A	N/A	N/A
9/1/2010	137.15	N/A	N/A	14.69	ND	14	N/A
9/14/2010	162.45	N/A	N/A	23.01	0.545	23	N/A
9/15/2010	164.63	4.35	<MDL	N/A	N/A	N/A	N/A
9/17/2010	168.63	N/A	N/A	N/A	N/A	-	2.5
9/20/2010	173.62	5.73	<MDL	N/A	N/A	N/A	N/A
9/21/2010	Carbon media changed.						
11/4/2010	43.40	5.23	N/A	N/A	N/A	N/A	N/A
1/12/2011	114.53	6.55	N/A	N/A	N/A	N/A	N/A
1/25/2011	137.78	N/A	N/A	28.54	ND	27	N/A
2/9/2011	156.47	N/A	N/A	31.87	1.755	30	N/A
2/9/2011	156.47	4.58	<MDL	N/A	N/A	N/A	N/A
2/14/2011	Carbon media changed.						
2/23/2011	17.72	N/A	N/A	24.46	ND	25	N/A
2/24/2011	20.09	6.64	N/A	N/A	N/A	N/A	N/A

Notes:

(1) All samples are taken using Tedlar Bags, except where otherwise noted as using Draeger® tubes f
(2) Inlet and outlet sample results from 5/19/10 are not accurate due to an error in collection, indicated by high nitrogen composition (>5%), and are not included in the minimum, maximum
(3) Outlet sample results from 6/29/10 are not accurate due to an error in collection, indicated by high nitrogen composition (>5%), and are not included in the minimum, maximum and average.
(4) Inlet and outlet sample results from AccuLabs on 8/12/10 are not accurate due to an error in collection, indicated by high nitrogen composition (>5%), and are not included in the minimum,
(5) Sample results from 8/19/10 are not consistent with sample results from other laboratories and are concluded to be erroneous and not included in the minimum, maximum and average.
(6) N/A indicates that the compound was not analyzed for.
(7) ND indicates non-detect.
(8) <MDL indicates that the result, if any, was less than the method detection limit.

APPENDIX C-1:

CO and NOx with Portable Analyzer Summary

CO and NOx with Portable Analyzer Summary
Plant 1 - Catalytic Oxidizer and Selective Catalytic Reduction

Date	Load (%)	DG (%)	Testing Time (min)	NH3 Draeger Tube (ppm)	Before Cat Ox		After Cat Ox		After SCR		CO Reduction	NOx Reduction
					CO (ppm) Adj to 15% O2	NOx (ppm) Adj to 15% O2	CO (ppm) Adj to 15% O2	NOx (ppm) Adj to 15% O2	CO (ppm) Adj to 15% O2	NOx (ppm) Adj to 15% O2		
3/29/2010	80	88	15	N/A	448.4	38.7	5.8	39.8	5.3	1.3	98.8%	96.6%
3/30/2010	82	95	15	N/A	453.0	33.5	0.1	34.2	3.3	4.9	99.3%	85.2%
3/31/2010	60	95	10	N/A	353.9	29.7	N/A	N/A	4.0	1.4	98.9%	95.4%
3/31/2010	80	95	10	N/A	431.2	33.9	N/A	N/A	9.2	4.5	97.9%	86.8%
3/31/2010	100	95	10	N/A	452.3	36.5	N/A	N/A	0.0	6.7	100.0%	81.6%
3/31/2010	110	95	10	N/A	446.2	41.9	N/A	N/A	0.3	5.8	99.9%	86.1%
3/31/2010	60	50	10	N/A	347.3	39.6	N/A	N/A	13.8	7.3	96.0%	81.6%
3/31/2010	80	50	10	N/A	472.0	39.9	N/A	N/A	11.5	6.0	97.6%	85.0%
3/31/2010	100	50	10	N/A	513.5	43.7	N/A	N/A	15.7	6.8	97.0%	84.5%
3/31/2010	110	50	10	N/A	478.7	45.8	N/A	N/A	3.4	9.3	99.3%	79.7%
4/1/2010	60	0	10	N/A	380.9	43.6	N/A	N/A	0.6	0.9	99.8%	97.9%
4/1/2010	80	0	10	N/A	559.9	44.1	N/A	N/A	1.3	1.3	99.8%	97.1%
4/1/2010	100	0	10	N/A	591.8	48.1	N/A	N/A	6.0	10.2	99.0%	78.7%
4/1/2010	110	0	10	N/A	532.9	51.9	N/A	N/A	1.3	11.4	99.8%	77.9%
4/7/2010	110	95	15	<MDL	367.5	46.2	1.7	47.3	1.6	10.1	99.6%	78.2%
4/14/2010	100	95	15	N/A	435.5	37.4	0.9	37.8	4.0	5.7	99.1%	84.8%
4/21/2010	90	95	15	<MDL	369.3	41.4	0	41.9	1.5	6.7	99.6%	83.8%
4/29/2010	94	95	15	<MDL	369.3	40.3	2.3	40.1	5.1	8.5	98.6%	78.8%
5/6/2010	100	95	15	<MDL	440.8	41.3	0.7	39.6	2.2	2.7	99.5%	93.5%
5/19/2010	100	95	15	<MDL	525.1	34.5	3.0	36.5	4.7	1.2	99.1%	96.5%
6/29/2010	100	97	15	<MDL	439.7	42.4	2.4	40.5	17.0	8.1	96.1%	81.0%
7/28/2010	95	97	15	<MDL	458.8	39.8	0.1	37.8	8.8	7.3	98.1%	81.7%
8/12/2010	100	96	15	<MDL	408.4	43.5	4.9	44.0	7.6	10.1	98.1%	76.7%
11/4/2010	100	96	15	<MDL	598.7	43.2	0.0	42.5	0.0	10.2	100.0%	76.3%
1/12/2011	100	96	15	<MDL	509.4	37.9	15.1	36.4	17.2	7.7	96.6%	79.7%
2/24/2011	100	95	15	<MDL	496.8	38.5	0.0	39.1	0.1	6.9	100.0%	82.1%

Notes:

(1) N/A indicates that this data was not collected.

(2) <MDL indicates that the result, if any, was less than the detection limit.

APPENDIX C-2:

Technical Memorandum:
OCSD Catalytic Oxidizer/SCR Pilot Study: VOC Evaluation

Technical Memorandum

Date: July 13, 2011

To: File

From: Kit Liang, Malcolm Pirnie, WHI; Daniel Stepner, Malcolm Pirnie, WHI

Re: OCSD Cat Ox/SCR Pilot Study: VOC Evaluation

Project No.: 0788-187

Project Background

The internal combustion (IC) engines at Orange County Sanitation District (OCSD) are subject to South Coast Air Quality Management District (SCAQMD) Rule 1110.2. Rule 1110.2 provides emission limits and monitoring requirements for all stationary and portable engines over 50 brake-horsepower (bhp). Rule 1110.2 (Emissions from Gaseous- and Liquid- Fueled Engines) was promulgated to reduce the NOx, CO and volatile organic compounds (VOC) emissions from engines over 50 bhp. On February 1, 2008, Rule 1110.2 was amended in order to achieve further emissions reductions from stationary engines based on the cleanest available technologies. Under the February 2008 amendments to Rule 1110.2 shown below, more stringent NOx, CO, and VOC limits were adopted, to become effective for biogas-fueled engines in July 2012 provided a technology assessment confirms that the limits below are achievable.

- NOx limit was lowered from 36 ppm (or ~ 45 ppm*) to 11 ppm at 15% O_2.
- VOC limit was lowered from 250 ppm* to 30 ppm at 15% O_2.
- CO limit was lowered from 2,000 ppm to 250 ppm at 15% O_2.

* Existing limits allow for an alternative emission limit for OCSD engines based on the engine efficiency correction factor.

A pilot study of a Johnson Matthey catalytic oxidizer/Selective Catalytic Reduction (Cat Ox/SCR) system was performed at OCSD Plant 1 on Engine 1 from April 2010 through March 2011. Design of the pilot system included an SCR system for NOx emission reduction, an oxidation catalyst unit for CO and VOC reduction (including formaldehyde), and a DGCS upstream from the IC engines for removal of siloxanes to prevent fouling of the catalysts. Additional benefits of the DGCS include the removal of total reduced sulfur and total volatile organic compounds. The DGCS cleaned the digester gas fuel for all three Plant 1 IC engines. However, the Cat Ox/SCR system was only installed on Engine 1. As part of this pilot testing program, a sampling program was initiated to determine the concentrations of VOCs at the inlet and outlet of the Cat Ox/SCR system. The sampling was performed by SCEC, a firm listed in the SCAQMD Laboratory Approval Program (LAP). The VOC sampling was performed using SCAQMD Method 25.3.

This memorandum describes the sampling method for VOCs used during the testing and the VOCs concentration results. In addition, the memorandum compares the result found for Engine 1 with results from a recent regulatory compliance study performed on Engines 1, 2, and 3 at Plant 1.

VOC Sampling SCAQMD Method 25.3

The SCAQMD compliance methods for testing for VOCs are SCAQMD Methods 25.1 and 25.3. In general, SCAQMD Method 25.1 is used to collect samples where VOC concentrations are greater or equal to 50 ppm as carbon (ppmC). SCAQMD Method 25.3 is used where VOC concentrations are less than 50 ppmC. With both methods, exhaust gas samples are drawn into evacuated canisters through condensate traps. In Method 25.3, the condensate, largely consisting of water, is collected in the traps at ice water temperature (~32°F), preventing unrecoverable VOC from being collected in the canisters. Based on previous sampling, VOC concentrations in the exhaust gas are expected to be below 50 ppm; therefore, SCAQMD Method 25.3 was used for this pilot study. During the pilot study, exhaust samples are taken at the engine exhaust, prior to the catalyst oxidizer, and at the stack exhaust, following the SCR and heat recovery boiler. Analysis was performed at the laboratory.

The VOC concentration as non-methane non-ethane organic compounds (NMNEOC) is determined by combining the independent analysis results of the condensate in each trap and the gas in the associated canister. The condensate is analyzed for total organic carbon by liquid injection into an infra-red organic carbon analyzer. The gaseous sample in the canister is analyzed for NMNEOC using a combination of gas chromatography, oxidizer, methanizer, and flame ionization detector. Carbon monoxide and fixed gases in the sample can be determined by analysis of the canister portion of the sample.

VOC Monitoring Results and Discussion

Pilot testing of the Cat Ox/SCR system commenced on April 1, 2010 and continued through March 31, 2011. Throughout the pilot testing, SCEC tested VOCs at the engine exhaust before the catalytic oxidizer and at the stack outlet after the SCR and heat recovery boiler on the roof of the Central Generator (CenGen) Building. Results of the VOC data are summarized in Table 1.

Table 1 presents a summary of the VOC field measurements using SCAQMD Method 25.3. The percent reduction of VOC ranged from 59.1% to 97.8%. The average concentration of VOC at the stack exhaust was 3.58 ppmv, below the emission limit of 30 ppmv in the Amended Rule 1110.2.

Table 1:
Measured VOC Concentrations – Plant 1 Engine 1

Date	Engine Exhaust (ppmv)	Stack Exhaust (ppmv)	% Reduction
4/7/2010	27.1	2.0	90.4
5/11/2010	33.0	0.7	97.8
8/12/2010	15.1	5.4	64.0
11/4/2010	10.3	4.2	59.1
2/24/2011	25.0	5.0	80.2
Average	**21.8**	**3.6**	**83.6**

Notes: 1. All concentrations are adjusted to 15% O_2.
2. All samples were collected using SCAQMD Method 25.3

Data measured during the pilot testing period was compared to VOC concentrations measured by SCEC for the *OCSD Plant No. 1 Unit Nos. 1, 2, 3 Rule 1110.2 8760 Hour & Permit Compliance Test Report for Year 2011*. Table 2 summarizes the annual permit compliance VOC test results for OCSD Plant No. 1. The Unit No. 1 (Engine 1) VOC stack exhaust concentration measured during the annual Rule 1110.2 compliance testing was 3.24 ppmv. This is in the same range of the VOC concentrations measured during the pilot testing period, confirming the effectiveness of the catalytic oxidizer in removing VOC from the engine exhaust.

Table 2:
Annual Rule 1110.2 Compliance Test VOC Concentrations - Plant No. 1

Date	Unit No. (Engine)	Sampling Method	Stack Exhaust (ppmv)
1/13/2011	1	SCAQMD Method 25.3	3.24
1/12/2011	2	SCAQMD Method 25.1	97.2
1/11/2011	3	SCAQMD Method 25.1	96.9

Note: 1. All concentrations are adjusted to 15% O_2.

As discussed earlier, the DGCS was installed on the digester gas header and provides cleaned digester gas fuel to all three IC engines. The Cat Ox/SCR post-combustion control was installed on Engine 1, but not on Unit Nos. 2 and 3 (Engines 2 and 3). As shown in Table 2, the VOC stack exhaust concentrations for Engines 2 and 3 were 97.2 and 96.9 ppmv, respectively. This was much higher than the VOC concentrations measured at the Engine 1 exhaust before the Cat Ox/SCR system during the pilot testing period, which averaged 21.84 ppmv VOCs. One possible explanation to this is the arrangement of the sampling port at Engine No. 1 before the catalytic oxidizer. Due to restrictions on placement of the Method 25.3 probe at the Engine No. 1 exhaust before the Cat Ox/SCR system, accuracy in taking this sample is reduced. Typically using sampling Method SCAQMD 25.3, two samples are gathered from two separate probes and the results of the analyses are averaged. SCAQMD mandates that when the results from the two samples differ by more than 20%, that the higher value of the two samples be reported. In the experience of the SCEC lab, this occurs approximately half of the time. Otherwise, the values are averaged.

In this instance, the valve at the engine exhaust sampling port was not large enough to co-locate two probes next to each other and it was not possible to expand the sampling port. Therefore, the sample and duplicate sample were not taken at the same time, but one after the other. The data presented in Table 2 above for the engine exhaust represents the higher of the two sample data results, in line with AQMD's general mandate. Despite the lower accuracy in the engine exhaust sample, the sample taken at the stack exhaust met the SCAQMD accuracy criteria. Moving forward, it is recommended to install a larger sampling port to allow for greater accuracy through the co-location of the Method 25.3 probes.

Conclusions and Recommendations

Upon review of the data from the five sampling events, it was determined that the catalytic oxidizer (with a DGCS) is successful in reducing the VOC concentration to below the emission limit of 30 ppmv in Amended Rule 1110.2. The catalytic oxidizer system met the vendor guarantee of 25 ppmvd VOCs. During the pilot testing period, the average VOC inlet concentration at the engine exhaust was 21.8 ppmv, and the average VOC outlet concentration at the stack exhaust was 3.6 ppmv. The VOC outlet concentration was confirmed during the OCSD Plant No. 1 annual permit compliance testing in January 2011 (see Table 2).

During the annual permit compliance testing in January 2011, it was also found that the VOC concentration at the Engine Nos. 2 and 3 Stack Exhaust were 97.2 ppmv and 96.9 ppmv, respectively. This is much higher than that measured at the Engine No. 1 exhaust before the catalytic oxidizer. This may have occurred due to restrictions with the Engine No. 1 exhaust sample port. In the future, it is recommended to install a larger sampling port at the engine exhaust.

References

1 CARB, 1991. "Method 430 – Determination of Formaldehyde and Acetaldehyde in Emissions from Stationary Sources." December 1991.

2 EPA, 2003. "Appendix A to Part 63 – Test Methods. Method 323 – Measurement of Formaldehyde Emissions from Natural Gas-Fired Stationary Sources – Acetyl Acetone Derivitization Method." Federal Register, Vol. 68, No. 9, January 14, 2003.

3 SCAQMD, 2000. "Method 25.3 – Determination of Low Concentration Non-Methane Non-Ethane Organic Compound Emissions from Clean Fueled Combustion Sources." March 2000.

APPENDIX C-3:

CEMS Emissions Summary

Validated Daily 15-Minute Block Average
Daily Average and Maximum Emissions Summary Data from CEMS
Plant 1 - Catalytic Oxidizer and Selective Catalytic Reduction

Date	Avg. Engine Exhaust NOx @15% O2 (ppmvd)	Average Stack Exhaust NOx @15% O2 (ppmvd)	Average Stack Exhaust CO @15%O2 (ppmvd)	Maximum Ammonia Slip	Maximum Engine Exhaust NOx @15% O2 (ppmvd)	Maximum Stack Exhaust NOx @15% O2 (ppmvd)	Maximum Stack Exhaust CO @15%O2 (ppmvd)	Average Engine Load (%)	Max Engine Load (%)	Average Fuel Ratio (% DG)	Notes
4/1/2010	33.49	-	6.20	-	44.32	-	8.97	96.13	113.65	0%	Note 1.
4/2/2010	31.28	-	5.70	-	34.35	-	6.28	96.84	100.74	96%	Note 1.
4/3/2010	30.16	-	5.75	-	31.61	-	6.24	97.55	101.02	91%	Note 1.
4/4/2010	30.05	-	5.82	-	32.05	-	6.33	96.80	103.18	83%	Note 1.
4/5/2010	33.96	-	5.84	-	36.08	-	6.31	95.15	101.43	90%	Note 1.
4/6/2010	34.03	-	5.78	-	37.00	-	6.73	94.82	100.79	74%	Note 1.
4/7/2010	35.47	-	5.58	-	38.97	-	6.08	96.88	105.06	96%	Note 1.
4/8/2010	32.89	-	5.93	-	37.44	-	7.87	91.57	101.69	94%	Note 1.
4/9/2010	31.93	-	5.78	-	33.69	-	6.28	97.27	100.60	96%	Note 1.
4/10/2010	31.49	-	5.93	-	33.18	-	6.34	96.90	100.78	92%	Note 1.
4/11/2010	30.94	-	6.04	-	33.04	-	6.55	94.72	99.67	91%	Note 1.
4/12/2010	31.69	-	6.05	-	34.34	-	6.71	88.29	96.25	88%	Note 1.
4/13/2010	33.11	-	5.95	-	37.06	-	6.53	88.30	98.81	90%	Note 1.
4/14/2010	31.98	-	5.87	-	35.12	-	6.31	95.47	100.75	89%	Note 1.
4/15/2010	31.09	-	5.98	-	34.46	-	6.37	97.02	100.38	90%	Note 1.
4/16/2010	31.36	-	5.95	-	33.19	-	6.26	96.80	100.46	92%	Note 1.
4/17/2010	30.94	-	5.92	-	32.69	-	6.25	97.66	104.81	93%	Note 1.
4/18/2010	30.70	-	5.95	-	34.11	-	6.47	95.54	100.86	95%	Note 1.
4/19/2010	30.28	-	6.09	-	33.10	-	6.81	90.86	99.29	88%	Note 1.
4/20/2010	29.62	-	6.10	-	33.35	-	6.44	83.53	93.10	90%	Note 1.
4/21/2010	33.03	-	5.61	-	34.76	-	5.88	95.39	100.22	93%	Note 1.
4/22/2010	33.03	-	5.62	-	35.49	-	5.91	97.64	100.88	96%	Note 1.
4/23/2010	33.73	-	5.87	-	35.89	-	7.05	96.10	100.84	96%	Note 1.
4/24/2010	33.49	-	5.98	-	35.68	-	6.15	97.92	102.18	96%	Note 1.
4/25/2010	30.79	-	6.18	-	32.34	-	6.54	96.58	100.34	91%	Note 1.
4/26/2010	30.40	-	6.22	-	32.20	-	6.75	92.60	99.67	86%	Note 1.
4/27/2010	31.10	-	6.13	-	32.92	-	6.83	95.33	101.54	86%	Note 1.
4/28/2010	32.11	-	6.19	-	36.67	-	7.37	93.53	102.53	53%	Note 1.
4/29/2010	35.53	-	5.67	-	38.83	-	6.40	98.71	107.61	96%	Note 1.
4/30/2010	34.85	-	5.58	-	37.68	-	5.79	103.15	106.09	96%	Note 1.
5/1/2010	32.93	-	5.78	-	34.68	-	6.00	102.47	106.53	96%	Note 1.
5/2/2010	34.26	-	5.81	-	36.48	-	6.25	102.95	106.06	92%	Note 1.
5/3/2010	34.39	-	6.18	-	42.06	-	9.72	96.31	105.57	53%	Note 1.
5/4/2010	32.80	-	5.97	-	34.46	-	6.53	92.11	100.49	0%	Note 1.
5/5/2010	26.49	-	4.80	-	27.54	-	5.18	83.99	92.92	0%	Note 1.
5/6/2010	32.64	-	5.19	-	35.45	-	5.81	102.76	106.54	0%	Note 1.
5/7/2010	32.33	-	5.52	-	34.26	-	5.96	103.38	107.95	96%	Note 1.
5/8/2010	32.14	-	5.66	-	34.01	-	6.13	103.18	106.94	85%	Note 1.
5/9/2010	31.33	-	5.82	-	36.50	-	6.30	96.36	105.53	89%	Note 1.
5/10/2010	31.77	-	5.76	-	36.68	-	7.46	85.73	98.86	86%	Note 1.
5/11/2010	33.55	-	5.59	-	38.04	-	6.35	97.79	106.06	89%	Note 1.
5/12/2010	32.02	-	5.73	-	37.30	-	6.66	102.01	106.44	55%	Note 1.
5/13/2010	31.47	-	5.93	-	33.54	-	6.54	97.90	106.97	0%	Note 1.
5/14/2010	33.74	-	5.68	-	35.92	-	5.94	102.47	107.02	87%	Note 1.
5/15/2010	34.32	-	5.74	-	36.26	-	5.92	102.79	106.02	87%	Note 1.
5/16/2010	32.94	-	5.77	-	35.24	-	6.25	103.30	106.55	87%	Note 1.
5/17/2010	32.28	-	5.75	-	34.83	-	6.31	100.58	105.76	94%	Note 1.
5/18/2010	30.24	-	5.90	-	34.62	-	6.57	100.79	106.94	96%	Note 1.
5/19/2010	30.15	-	5.85	-	31.65	-	6.68	101.48	107.08	86%	Note 1.
5/20/2010	31.29	-	5.88	-	34.10	-	6.42	103.01	107.64	90%	Note 1.
5/21/2010	30.16	-	6.12	-	33.08	-	6.66	102.86	107.93	96%	Note 1.
5/22/2010	32.54	-	5.84	-	35.08	-	6.09	103.12	106.52	90%	Note 1.
5/23/2010	34.07	-	5.90	-	36.53	-	6.40	102.80	107.51	93%	Note 1.
5/24/2010	32.96	-	5.99	-	36.36	-	6.39	102.46	109.29	90%	Note 1.
5/25/2010	30.21	-	5.98	-	33.13	-	6.43	98.64	107.62	91%	Note 1.

Date	Avg. Engine Exhaust NOx @15% O2 (ppmvd)	Average Stack Exhaust NOx @15% O2 (ppmvd)	Average Stack Exhaust CO @15%O2 (ppmvd)	Maximum Ammonia Slip	Maximum Engine Exhaust NOx @15% O2 (ppmvd)	Maximum Stack Exhaust NOx @15% O2 (ppmvd)	Maximum Stack Exhaust CO @15%O2 (ppmvd)	Average Engine Load (%)	Max Engine Load (%)	Average Fuel Ratio (% DG)	Notes
5/26/2010	31.18	-	6.06	-	33.84	-	6.44	101.02	107.79	90%	Note 1.
5/27/2010	32.54	-	6.62	-	42.79	-	7.39	107.57	116.77	0%	Note 1.
5/28/2010	32.54	-	7.13	-	36.76	-	7.87	108.29	112.89	90%	Note 1.
5/29/2010	33.32	-	7.21	-	38.06	-	8.14	108.48	113.00	90%	Note 1.
5/30/2010	32.29	-	7.14	-	37.57	-	7.81	105.35	111.41	95%	Note 1.
5/31/2010	32.38	-	7.09	-	34.35	-	7.85	102.68	110.76	93%	Note 1.
6/1/2010	32.12	-	7.08	-	34.42	-	7.70	99.23	106.01	91%	Note 1.
6/2/2010	32.10	-	7.12	-	35.69	-	7.82	99.22	109.84	92%	Note 1.
6/3/2010	32.60	-	7.21	-	35.06	-	7.62	102.76	106.04	90%	Note 1.
6/4/2010	31.77	-	7.65	-	34.64	-	8.26	102.72	107.91	90%	Note 1.
6/5/2010	30.68	-	8.03	-	33.03	-	8.47	102.76	106.89	0%	Note 1.
6/6/2010	31.73	-	8.66	-	33.23	-	9.22	103.14	106.57	90%	Note 1.
6/7/2010	29.42	-	8.50	-	34.22	-	10.27	92.20	107.57	87%	Note 1.
6/8/2010	28.04	3.67	8.82	5.25	30.71	6.70	10.15	89.57	106.09	93%	Urea injection set points modified to reduce ammonia slip.
6/9/2010	29.08	5.14	11.05	1.75	30.72	6.98	12.65	100.68	108.52	90%	
6/10/2010	29.03	4.96	14.33	1.38	32.07	6.50	17.45	103.62	107.96	90%	
6/11/2010	35.28	8.58	14.73	3.66	39.35	10.49	17.69	88.07	107.98	0%	
6/12/2010	35.15	8.40	13.39	2.46	41.26	13.87	16.32	87.35	104.66	0%	Engine operated on Natural Gas from 17:26 to 17:31.
6/13/2010	28.12	4.80	10.94	1.31	30.63	6.24	12.90	92.08	101.85	96%	
6/14/2010	27.52	4.87	9.13	1.21	29.15	6.22	9.61	85.14	94.49	54%	The CEMS failed calibration repeatedly (both NOx and CO low range were out of control). Adjustments were made to bring it back into calibration (Note 2).
6/15/2010	28.04	4.60	9.54	1.12	32.15	6.77	11.00	91.91	99.76	87%	
6/16/2010	30.75	5.59	9.59	1.13	35.26	7.78	10.36	97.30	107.73	81%	
6/17/2010	30.87	5.62	9.92	1.15	34.07	7.32	10.61	103.26	105.74	96%	
6/18/2010	29.87	4.94	9.90	0.97	31.55	6.03	10.60	101.24	105.90	96%	
6/19/2010	31.23	6.02	9.03	1.34	33.29	7.23	9.56	97.62	101.06	96%	
6/20/2010	32.09	6.44	8.69	1.74	34.59	7.71	9.19	97.83	102.80	96%	
6/21/2010	34.17	7.36	8.40	1.69	36.50	9.06	9.07	99.29	103.92	91%	
6/22/2010	33.88	7.24	8.42	2.15	37.69	8.89	9.11	98.75	106.15	90%	
6/23/2010	33.03	6.83	8.28	2.11	36.24	8.99	9.10	97.58	104.97	94%	
6/24/2010	32.86	6.89	8.65	2.40	36.61	9.15	9.41	102.87	106.83	96%	Urea injection shut off for urea delivery and level sensor calibration from 8:08 to 9:22 (Note 3).
6/25/2010	32.53	6.83	8.91	2.09	34.24	7.73	9.31	103.43	106.78	92%	
6/26/2010	33.67	7.61	8.40	3.11	38.08	8.94	8.93	103.06	105.96	94%	
6/27/2010	33.46	7.88	8.21	4.39	38.36	8.96	8.89	103.32	106.45	98%	CEMS inlet sample flow alarm occurred causing invalid data. CEMTEK technician responded and found sample pump to be in need of a rebuild. Necessary repairs were made.
6/28/2010	34.80	7.67	8.38	2.47	36.82	9.10	8.98	103.11	106.70	98%	
6/29/2010	34.16	7.61	8.46	1.98	36.75	8.95	9.29	103.41	108.30	93%	
6/30/2010	34.39	7.83	8.09	3.01	37.94	10.29	9.57	99.16	110.60	85%	
7/1/2010	34.16	7.43	7.83	2.14	35.40	8.14	7.91	93.56	95.94	92%	
7/2/2010	N/A	N/A	N/A	N/A	0.00	N/A	N/A	N/A	N/A	0%	The engine experience high NOx inlet at the engine exhaust due to a new automation issue, which in turn caused high NOx at the stack outlet (Note 4).
7/3/2010	N/A	N/A	N/A	N/A	0.00	N/A	N/A	N/A	N/A	0%	
7/4/2010	36.43	8.74	8.02	2.06	39.94	10.37	9.18	99.37	105.85	90%	
7/5/2010	35.95	8.30	8.13	2.37	39.78	10.33	9.24	100.91	105.97	89%	
7/6/2010	34.81	7.86	7.80	2.21	38.84	9.78	9.13	97.97	105.00	0%	Note 2.
7/7/2010	33.89	7.49	7.47	2.68	37.70	9.38	8.32	93.48	100.26	92%	
7/8/2010	32.69	6.79	8.18	1.86	36.29	8.77	9.23	97.97	107.36	83%	
7/9/2010	32.07	6.43	8.70	1.32	34.42	7.76	9.33	97.63	99.70	83%	
7/10/2010	32.57	6.70	8.22	1.68	35.97	8.18	9.27	97.70	101.85	83%	
7/11/2010	31.92	6.56	8.09	1.56	36.21	8.52	9.15	92.72	99.52	87%	
7/12/2010	32.69	7.23	7.72	1.86	37.08	9.47	8.95	90.23	97.66	89%	
7/13/2010	33.00	7.19	7.79	2.12	36.37	8.91	8.93	96.10	101.79	88%	
7/14/2010	33.28	7.38	7.71	2.04	38.59	10.02	8.82	93.08	99.29	91%	
7/15/2010	33.49	7.34	7.93	2.26	37.32	9.50	8.58	98.93	103.17	97%	
7/16/2010	31.95	6.75	8.23	1.67	33.71	7.98	8.88	98.17	103.58	87%	

Validated Daily 15-Minute Block Average
Daily Average and Maximum Emissions Summary Data from CEMS
Plant 1 - Catalytic Oxidizer and Selective Catalytic Reduction

Date	Avg. Engine Exhaust NOx @15% O2 (ppmvd)	Average Stack Exhaust NOx @15% O2 (ppmvd)	Average Stack Exhaust CO @15%O2 (ppmvd)	Maximum Ammonia Slip	Maximum Engine Exhaust NOx @15% O2 (ppmvd)	Maximum Stack Exhaust NOx @15% O2 (ppmvd)	Maximum Stack Exhaust CO @15%O2 (ppmvd)	Average Engine Load (%)	Max Engine Load (%)	Average Fuel Ratio (% DG)	Notes
7/17/2010	33.16	7.43	7.87	2.39	37.15	9.46	9.08	93.85	105.06	89%	
7/18/2010	32.37	7.02	7.83	2.02	35.65	9.00	8.90	94.85	101.40	90%	
7/19/2010	32.74	7.22	7.91	2.46	36.69	9.50	9.16	95.15	101.60	88%	
7/20/2010	32.05	6.86	7.80	39.38	36.12	10.44	11.46	94.30	100.26	0%	The engine was brought offline at the request of the OCSD's contractor who is performing electrical upgrades (Note 2).
7/21/2010	32.46	6.85	7.99	1.88	34.65	7.73	8.99	98.29	102.81	94%	
7/22/2010	32.78	6.99	7.97	2.15	35.41	8.30	9.11	95.07	102.88	87%	
7/23/2010	30.76	5.96	8.36	1.75	33.43	7.40	9.44	95.39	99.27	87%	
7/24/2010	31.02	6.42	8.42	7.59	34.77	9.33	42.23	93.60	118.80	0%	Note 2.
7/25/2010	32.71	6.94	8.02	3.26	37.17	9.35	9.29	97.57	102.19	89%	
7/26/2010	34.25	7.62	7.55	100.43	41.43	9.23	8.48	96.06	107.34	0%	Note 2.
7/27/2010	32.69	6.99	7.57	2.16	38.25	9.15	8.49	92.14	99.98	87%	
7/28/2010	32.15	6.88	7.74	3.47	35.77	8.68	9.26	93.20	112.96	0%	Note 2.
7/29/2010	32.04	7.22	6.61	2.48	34.72	8.63	8.44	93.08	99.08	0%	Note 2.
7/30/2010	30.92	6.71	6.38	2.07	32.76	7.60	6.67	94.17	101.75	90%	
7/31/2010	30.03	6.34	6.48	2.73	31.93	7.27	7.61	92.62	100.70	90%	
8/1/2010	30.79	6.69	6.64	2.84	33.38	8.17	7.67	93.19	104.33	90%	
8/2/2010	31.93	7.34	6.42	2.42	36.03	9.55	7.36	91.59	97.50	89%	
8/3/2010	32.58	7.68	6.26	25.61	36.79	9.42	7.44	92.77	99.37	0%	Note 2.
8/4/2010	32.44	7.78	6.18	10.42	34.43	9.34	7.31	94.30	98.94	0%	Note 2.
8/5/2010	31.95	7.25	6.51	3.20	35.74	9.00	13.21	89.75	99.70	0%	Note 2. High Stack Exhaust NOx due to Natural Gas fuel.
8/6/2010	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0%	
8/7/2010	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0%	
8/8/2010	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0%	Engine was offline from 8/5/10 16:09 through 8/11/10 7:48.
8/9/2010	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0%	
8/10/2010	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0%	
8/11/2010	34.39	9.27	6.08	3.49	37.74	10.98	6.88	90.62	95.53	0%	Note 2.
8/12/2010	34.01	8.74	6.41	3.19	37.25	10.07	7.49	93.14	102.71	0%	
8/13/2010	32.57	8.41	6.40	3.06	37.04	11.15	7.02	85.86	97.19	97%	
8/14/2010	33.00	8.53	6.38	3.91	37.21	10.60	7.03	86.13	92.47	96%	
8/15/2010	31.66	7.74	6.73	3.24	35.65	9.73	7.53	86.67	94.22	84%	
8/16/2010	32.48	8.43	6.52	3.42	37.09	11.79	7.34	82.17	86.64	0%	Note 2.
8/17/2010	32.96	8.93	6.48	3.45	37.66	11.46	7.01	84.22	91.31	0%	Note 2.
8/18/2010	34.78	9.68	6.46	4.98	40.13	12.49	6.99	90.49	97.30	0%	High Stack Exhaust NOx due to Natural Gas fuel.
8/19/2010	33.37	8.98	6.70	3.88	37.98	12.01	7.22	90.84	105.13	0%	High Stack Exhaust NOx due to Natural Gas fuel.
8/20/2010	33.29	8.98	6.55	5.40	38.36	11.54	7.31	91.00	95.18	90%	High Stack Exhaust NOx due to Natural Gas fuel.
8/21/2010	33.27	8.80	6.63	5.09	37.79	10.62	7.58	92.52	96.82	88%	
8/22/2010	32.57	8.36	6.71	4.44	37.77	11.61	7.57	90.78	98.04	87%	
8/23/2010	32.37	8.33	6.80	5.17	38.56	12.47	7.69	86.52	107.28	87%	
8/24/2010	29.99	7.10	6.83	3.93	37.32	12.07	7.72	80.59	105.53	0%	High Stack Exhaust NOx due to Natural Gas fuel.
8/25/2010	30.34	7.17	6.62	4.24	37.22	11.50	7.48	85.12	107.70	0%	High Stack Exhaust NOx due to Natural Gas fuel.
8/26/2010	29.45	6.37	6.92	3.98	34.92	9.43	7.51	87.33	105.39	86%	
8/27/2010	29.78	6.58	6.82	3.11	35.83	9.86	7.57	86.61	103.34	84%	
8/28/2010	30.79	7.18	6.75	3.30	36.03	10.15	7.15	86.40	100.08	90%	
8/29/2010	30.77	7.03	6.85	4.73	36.72	10.26	7.82	85.69	100.49	84%	
8/30/2010	29.61	6.07	7.11	1.88	35.04	9.48	8.06	79.22	99.68	0%	Note 2.
8/31/2010	29.05	5.76	7.07	5.45	35.34	9.77	7.77	78.41	97.15	0%	Note 2.
9/1/2010	33.39	8.60	6.69	4.19	40.53	14.28	7.51	87.49	106.41	84%	
9/2/2010	32.65	8.22	6.77	6.03	39.58	13.23	7.54	84.66	99.47	84%	
9/3/2010	32.90	8.40	6.63	8.72	39.26	12.82	7.07	89.29	109.77	91%	
9/4/2010	33.26	8.65	6.61	5.38	38.50	11.94	7.43	90.48	107.93	86%	
9/5/2010	30.00	6.86	7.14	2.32	35.04	9.24	7.90	83.59	99.00	72%	
9/6/2010	29.93	6.56	7.48	1.93	32.05	7.69	7.98	80.49	90.32	69%	
9/7/2010	31.27	7.36	7.27	2.65	33.15	8.54	7.75	79.44	83.96	71%	
9/8/2010	35.14	9.79	6.52	5.14	42.28	15.88	7.21	87.84	107.84	90%	

Validated Daily 15-Minute Block Average
Daily Average and Maximum Emissions Summary Data from CEMS
Plant 1 - Catalytic Oxidizer and Selective Catalytic Reduction

Date	Avg. Engine Exhaust	Average Stack Exhaust		Maximum	Maximum Engine Exhaust	Maximum Stack Exhaust		Average Engine Load (%)	Max Engine Load (%)	Average Fuel Ratio (% DG)	Notes
	NOx @15% O2 (ppmvd)	NOx @15% O2 (ppmvd)	CO @15%O2 (ppmvd)	Ammonia Slip	NOx @15% O2 (ppmvd)	NOx @15% O2 (ppmvd)	CO @15%O2 (ppmvd)				
9/9/2010	32.88	9.10	6.51	11.65	41.40	13.94	7.21	91.86	107.79	91%	
9/10/2010	31.34	8.32	6.78	6.44	37.96	12.85	7.26	91.29	108.76	90%	
9/11/2010	29.43	7.26	6.89	4.87	33.60	9.66	7.51	86.16	105.12	86%	
9/12/2010	28.30	6.60	7.12	3.58	32.01	8.68	7.70	84.15	100.06	84%	
9/13/2010	28.95	6.89	7.27	3.96	33.22	9.30	7.90	82.00	97.27	78%	
9/14/2010	29.73	7.52	7.10	4.40	38.04	13.94	9.50	84.29	99.48	22%	
9/15/2010	31.12	8.14	6.94	5.71	35.50	11.23	7.39	96.23	108.48	92%	
9/16/2010	31.08	8.35	6.84	7.25	39.84	15.22	7.35	93.14	108.14	82%	
9/17/2010	31.23	8.67	6.76	6.46	36.62	11.98	9.99	91.46	110.09	0%	
9/18/2010	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0%	Engine was offline from 9/17/10 17:04 through 9/20/10 8:32.
9/19/2010	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0%	
9/20/2010	31.34	7.02	7.65	2.28	32.94	7.66	9.02	71.18	73.79	0%	Note 2.
9/21/2010	26.63	5.42	6.19	2.28	27.52	6.25	7.07	75.34	78.16	0%	Note 2.
9/22/2010	31.30	8.83	6.33	6.79	36.26	13.07	6.92	93.35	108.12	95%	
9/23/2010	31.26	8.62	6.52	6.13	36.23	12.79	7.10	96.28	108.32	98%	
9/24/2010	28.18	6.71	6.84	4.96	33.98	10.56	7.30	93.68	108.80	90%	
9/25/2010	27.04	6.35	6.68	3.71	29.74	8.06	7.15	83.96	103.31	92%	
9/26/2010	27.99	6.91	6.57	6.63	31.71	9.43	7.21	80.01	92.42	94%	
9/27/2010	28.73	7.14	6.69	4.94	34.90	12.61	7.70	81.03	97.24	85%	
9/28/2010	27.94	6.54	6.96	7.53	34.81	11.63	7.62	75.23	86.85	84%	
9/29/2010	28.91	7.65	6.80	9.74	33.59	10.20	7.48	81.73	91.75	81%	
9/30/2010	29.53	8.16	6.47	7.19	36.18	13.61	6.91	93.46	106.94	90%	
10/1/2010	27.07	6.68	6.58	5.20	29.46	8.08	7.00	83.91	92.78	89%	
10/2/2010	26.23	6.11	6.62	7.69	31.27	9.76	7.11	85.34	108.61	91%	
10/3/2010	25.86	5.71	6.65	3.04	28.55	7.08	7.14	82.10	98.20	90%	
10/4/2010	28.04	6.72	6.90	8.24	32.57	9.05	8.18	74.60	87.54	89%	
10/5/2010	28.81	6.89	6.83	7.19	33.02	10.71	8.00	72.84	83.41	89%	
10/6/2010	29.44	7.30	6.59	5.16	33.33	9.77	7.30	76.33	90.18	94%	
10/7/2010	29.43	7.25	6.66	14.29	32.75	9.50	7.31	76.26	91.66	95%	
10/8/2010	28.77	7.11	6.51	3.99	33.08	9.84	7.05	79.63	93.66	96%	
10/9/2010	28.78	7.31	6.47	4.17	32.12	9.47	6.90	85.42	99.26	98%	
10/10/2010	27.43	6.54	6.36	4.29	31.20	8.63	6.86	84.93	103.80	98%	
10/11/2010	27.52	6.30	6.45	3.76	33.05	8.60	7.23	79.05	101.14	93%	
10/12/2010	26.54	N/A	6.40	N/A	29.19	N/A	6.83	76.03	86.49	0%	
10/13/2010	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0%	
10/14/2010	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0%	
10/15/2010	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0%	
10/16/2010	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0%	
10/17/2010	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0%	
10/18/2010	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0%	
10/19/2010	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0%	
10/20/2010	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0%	
10/21/2010	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0%	Engine was shut down at 8:40 due to lack of low range calibration gas for the Stack
10/22/2010	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0%	Exhaust CEMS monitor. Data is missing from 16:02 to 17:06.
10/23/2010	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0%	
10/24/2010	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0%	
10/25/2010	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0%	
10/26/2010	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0%	
10/27/2010	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0%	
10/28/2010	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0%	
10/29/2010	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0%	
10/30/2010	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0%	
10/31/2010	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0%	
11/1/2010	28.67	6.50	7.49	3.13	31.86	9.42	8.49	75.34	96.94	0%	Note 2.
11/2/2010	28.19	6.54	7.54	4.81	33.32	9.67	8.06	74.82	83.23	89%	

Date	Avg. Engine Exhaust NOx @15% O2 (ppmvd)	Average Stack Exhaust NOx @15% O2 (ppmvd)	Average Stack Exhaust CO @15%O2 (ppmvd)	Maximum Ammonia Slip	Maximum Engine Exhaust NOx @15% O2 (ppmvd)	Maximum Stack Exhaust NOx @15% O2 (ppmvd)	Maximum Stack Exhaust CO @15%O2 (ppmvd)	Average Engine Load (%)	Max Engine Load (%)	Average Fuel Ratio (% DG)	Notes
11/3/2010	30.47	8.48	7.30	6.92	34.59	10.70	8.08	84.85	107.53	95%	
11/4/2010	31.14	8.99	7.19	7.27	34.38	10.70	7.68	91.85	109.16	93%	
11/5/2010	30.89	8.88	7.14	5.73	34.94	11.50	8.30	89.41	105.72	98%	
11/6/2010	28.41	7.19	7.19	6.18	32.85	10.10	8.08	85.70	96.36	88%	
11/7/2010	28.75	7.39	7.16	4.18	33.17	9.76	8.08	87.11	104.47	90%	
11/8/2010	30.20	8.10	6.93	5.35	37.51	13.37	8.61	90.50	105.21	48%	
11/9/2010	29.42	7.56	6.90	5.04	32.09	9.39	7.46	81.89	96.84	88%	
11/10/2010	27.07	6.11	7.01	2.81	29.85	8.39	7.61	79.84	97.91	92%	
11/11/2010	31.51	8.89	6.60	7.53	36.58	13.76	7.47	83.93	94.48	92%	
11/12/2010	31.50	8.90	6.86	5.30	37.28	13.42	7.62	88.38	102.32	98%	
11/13/2010	30.19	8.12	6.83	7.52	32.92	9.48	7.38	88.97	98.93	92%	
11/14/2010	28.00	6.92	7.06	6.65	32.41	8.95	7.98	80.73	91.53	90%	
11/15/2010	29.03	7.45	6.94	5.45	33.72	10.72	7.72	80.10	92.11	86%	
11/16/2010	28.04	7.06	6.87	3.45	43.68	13.94	7.92	88.64	102.38	0%	Note 2.
11/17/2010	24.94	5.16	7.08	1.84	26.49	6.38	7.76	82.87	89.68	0%	Note 2.
11/18/2010	25.33	5.25	7.09	4.72	28.62	7.14	7.74	83.83	102.51	0%	Note 2.
11/19/2010	26.67	6.58	7.00	4.28	32.24	12.23	7.82	84.51	95.55	73%	
11/20/2010	26.91	6.40	6.92	3.96	32.90	10.08	7.68	88.49	95.64	90%	
11/21/2010	26.92	6.21	7.00	3.63	31.24	8.02	7.93	79.79	91.55	91%	
11/22/2010	28.97	7.23	6.83	3.81	32.02	8.49	7.64	80.99	98.00	94%	
11/23/2010	28.19	6.83	6.65	3.49	31.73	9.26	7.24	84.08	97.69	98%	
11/24/2010	29.29	7.56	6.63	7.10	33.61	9.78	7.18	90.65	106.51	98%	
11/25/2010	31.81	8.98	6.51	5.52	34.83	10.43	7.06	90.37	96.97	0%	Note 2.
11/26/2010	33.06	9.83	6.51	5.39	36.68	12.59	7.11	90.34	100.05	94%	
11/27/2010	31.95	9.09	6.49	7.26	36.87	11.96	7.01	88.59	97.10	92%	
11/28/2010	31.77	8.99	6.55	7.36	35.35	11.16	7.46	85.58	96.93	93%	
11/29/2010	30.94	8.22	6.68	3.65	34.51	9.98	7.49	83.60	97.89	0%	
11/30/2010	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0%	
12/1/2010	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0%	
12/2/2010	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0%	
12/3/2010	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0%	
12/4/2010	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0%	
12/5/2010	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0%	
12/6/2010	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0%	
12/7/2010	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0%	
12/8/2010	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0%	
12/9/2010	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0%	
12/10/2010	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0%	
12/11/2010	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0%	
12/12/2010	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0%	
12/13/2010	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0%	
12/14/2010	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0%	Engine offline on 11/29/10 at 15:29 through 12/29/10 at 11:57.
12/15/2010	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0%	
12/16/2010	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0%	
12/17/2010	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0%	
12/18/2010	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0%	
12/19/2010	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0%	
12/20/2010	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0%	
12/21/2010	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0%	
12/22/2010	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0%	
12/23/2010	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0%	
12/24/2010	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0%	
12/25/2010	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0%	
12/26/2010	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0%	
12/27/2010	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0%	

Date	Avg. Engine Exhaust NOx @15% O2 (ppmvd)	Average Stack Exhaust NOx @15% O2 (ppmvd)	Average Stack Exhaust CO @15%O2 (ppmvd)	Maximum Ammonia Slip	Maximum Engine Exhaust NOx @15% O2 (ppmvd)	Maximum Stack Exhaust NOx @15% O2 (ppmvd)	Maximum Stack Exhaust CO @15%O2 (ppmvd)	Average Engine Load (%)	Max Engine Load (%)	Average Fuel Ratio (% DG)	Notes
12/28/2010	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0%	
12/29/2010	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0%	NOx probe at Engine Exhaust offline. The engine was not out of compliance and continued to run despite high NOx at the stack exhaust.
12/30/2010	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0%	
12/31/2010	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0%	
1/1/2011	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0%	After restart of the system on 12/29/10, plant operators had isolated and not checked the urea injection system. Once checked, the urea supply line was isolated, the urea pump noisy, the air supply to the injection lance was isolated, and the urea filter housing was leaking. Johnson Matthey replaced the #1 urea pump on 1/13/11 (Note 4).
1/2/2011	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0%	
1/3/2011	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0%	
1/4/2011	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0%	
1/5/2011	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0%	Engine offline to relocate engine exhaust NOx probe and replace umbilical line.
1/6/2011	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0%	
1/7/2011	31.43	7.75	7.43	3.34	32.61	8.39	7.76	104.77	107.37	96%	Urea injection was not turned on until 1 hour after engine start-up, data for the hour when the urea system was not online plus 30 minutes of start-up time is excluded from the data set (Note 3).
1/8/2011	31.05	7.35	7.63	2.57	32.70	8.42	8.05	102.22	106.83	95%	
1/9/2011	30.36	7.13	7.16	1.87	33.10	9.12	7.84	88.25	103.01	90%	
1/10/2011	30.98	7.45	7.02	2.26	34.84	9.52	7.50	84.08	96.68	94%	
1/11/2011	32.83	8.21	7.13	2.66	38.26	12.38	7.97	93.99	109.26	85%	
1/12/2011	31.94	7.33	7.70	1.96	34.05	9.25	8.22	100.93	107.27	96%	
1/13/2011	30.20	6.29	7.72	1.79	32.40	7.88	8.77	95.71	108.38	96%	
1/14/2011	32.85	7.97	7.59	2.64	35.06	9.50	8.06	104.41	108.41	96%	
1/15/2011	31.76	7.65	7.52	2.30	34.36	9.47	8.40	99.59	108.97	95%	
1/16/2011	30.89	7.16	8.14	2.01	32.24	8.08	8.73	103.93	110.94	98%	
1/17/2011	29.99	6.82	7.76	2.13	35.39	9.30	8.56	96.90	105.58	81%	
1/18/2011	29.70	6.77	7.59	2.49	32.44	8.50	8.38	94.12	106.01	90%	
1/19/2011	27.21	4.94	7.35	1.59	31.53	7.73	8.14	84.34	103.41	93%	
1/20/2011	30.55	7.39	7.21	13.98	35.22	11.59	7.93	86.34	101.04	91%	
1/21/2011	29.15	6.87	7.51	3.58	33.64	9.89	8.38	87.00	93.08	98%	
1/22/2011	26.97	5.23	7.45	1.60	30.15	7.37	8.44	85.37	96.58	97%	
1/23/2011	29.30	6.81	7.15	2.33	32.08	8.56	7.96	84.82	96.24	98%	
1/24/2011	29.55	6.73	7.01	2.49	32.13	8.12	8.05	78.79	92.24	87%	
1/25/2011	29.54	6.13	7.54	2.68	32.04	7.78	8.41	70.52	85.60	70%	
1/26/2011	31.52	7.78	6.99	3.18	34.94	9.54	8.05	87.50	108.13	86%	
1/27/2011	30.33	7.41	7.15	2.34	33.96	8.76	7.77	86.61	106.21	96%	
1/28/2011	29.42	6.73	7.56	2.37	32.77	8.88	8.16	92.70	107.40	96%	
1/29/2011	26.64	4.59	7.83	0.96	29.23	6.26	8.37	88.57	97.08	96%	
1/30/2011	26.98	5.02	7.08	1.03	28.37	6.04	7.56	80.00	86.47	94%	
1/31/2011	28.13	5.45	7.26	2.24	36.23	10.64	8.80	75.28	91.23	77%	
2/1/2011	28.53	5.75	7.32	2.79	32.14	7.92	8.48	73.98	84.95	87%	
2/2/2011	33.07	7.86	7.06	5.22	38.46	11.02	8.07	71.26	78.57	88%	
2/3/2011	29.41	6.08	7.14	1.60	32.47	7.39	7.71	80.11	87.92	94%	
2/4/2011	28.76	5.60	7.90	1.42	32.21	7.37	8.90	92.09	104.87	93%	
2/5/2011	27.35	5.33	7.83	0.93	29.39	6.31	8.46	88.44	96.01	91%	
2/6/2011	26.70	4.30	7.87	2.09	28.72	6.37	8.61	80.20	84.32	83%	
2/7/2011	28.87	6.01	7.70	1.25	30.14	7.24	8.18	80.59	84.04	0%	
2/8/2011	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0%	Engine offline 2/7/11 9:48 to 2/14/11 17:08 to change DGCS carbon media.
2/9/2011	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0%	
2/10/2011	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0%	
2/11/2011	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0%	
2/12/2011	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0%	
2/13/2011	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0%	
2/14/2011	29.60	7.32	6.76	5.31	31.62	10.02	7.71	90.54	97.53	0%	Note 2.
2/15/2011	29.97	7.00	7.40	2.70	34.01	8.68	7.93	95.74	106.86	98%	
2/16/2011	29.37	6.58	7.55	2.65	33.09	8.65	8.24	98.00	105.83	98%	
2/17/2011	32.25	8.07	7.48	3.30	34.04	9.81	8.23	104.74	111.50	98%	
2/18/2011	31.24	7.53	7.82	2.31	33.91	9.15	8.54	106.56	111.92	98%	

Validated Daily 15-Minute Block Average
Daily Average and Maximum Emissions Summary Data from CEMS
Plant 1 - Catalytic Oxidizer and Selective Catalytic Reduction

Date	Avg. Engine Exhaust NOx @15% O2 (ppmvd)	Average Stack Exhaust NOx @15% O2 (ppmvd)	Average Stack Exhaust CO @15%O2 (ppmvd)	Maximum Ammonia Slip	Maximum Engine Exhaust NOx @15% O2 (ppmvd)	Maximum Stack Exhaust NOx @15% O2 (ppmvd)	Maximum Stack Exhaust CO @15%O2 (ppmvd)	Average Engine Load (%)	Max Engine Load (%)	Average Fuel Ratio (% DG)	Notes
2/19/2011	30.92	7.36	7.55	2.81	33.90	9.76	8.31	102.93	110.40	98%	
2/20/2011	29.65	6.85	7.06	2.09	32.21	8.18	7.83	91.32	103.02	96%	
2/21/2011	29.49	6.57	6.81	3.01	34.00	8.82	7.57	81.64	91.69	93%	
2/22/2011	29.82	6.69	6.69	1.67	32.47	8.87	7.38	82.92	94.52	98%	
2/23/2011	31.09	7.21	7.18	1.64	33.45	8.16	7.92	99.43	109.78	98%	
2/24/2011	31.65	7.30	7.47	1.73	34.03	8.36	8.49	102.95	110.44	98%	
2/25/2011	33.13	8.13	7.39	4.04	34.16	9.47	7.71	106.44	111.02	0%	
2/26/2011	31.50	7.57	7.07	2.48	33.15	8.55	7.76	101.16	110.09	98%	
2/27/2011	33.42	8.34	6.97	2.93	36.58	10.04	7.36	100.53	108.17	98%	
2/28/2011	31.80	7.81	6.86	3.10	36.29	9.77	7.51	90.10	107.79	95%	
3/1/2011	30.14	6.79	7.14	2.65	32.51	9.02	7.88	91.95	105.72	98%	
3/2/2011	29.41	6.16	7.89	2.23	37.66	8.02	8.71	97.69	107.61	0%	Note 2.
3/3/2011	27.86	5.47	8.17	1.59	29.72	6.73	8.74	96.80	107.33	94%	
3/4/2011	28.83	6.08	8.46	1.39	30.85	7.23	8.87	102.94	110.40	98%	
3/5/2011	29.09	6.35	8.42	2.79	31.91	8.58	9.06	102.87	109.47	98%	
3/6/2011	26.63	5.01	7.89	1.43	28.70	6.04	8.86	91.24	102.92	95%	
3/7/2011	27.81	6.04	7.38	3.36	32.91	9.41	8.20	89.45	100.37	98%	
3/8/2011	28.03	6.00	7.69	2.04	30.45	7.55	8.68	91.40	103.44	98%	
3/9/2011	27.70	5.78	7.74	1.63	28.67	6.37	8.21	91.79	96.55	0%	Note 2.
3/10/2011	26.98	5.87	7.92	2.28	28.96	7.08	8.73	93.76	101.35	0%	Note 2.
3/11/2011	27.73	6.20	7.84	2.26	29.32	7.36	8.68	93.95	102.83	98%	
3/12/2011	28.37	6.49	7.67	2.08	29.98	7.32	8.58	94.09	106.19	97%	
3/13/2011	28.04	6.55	7.24	2.32	30.87	7.94	7.92	86.38	94.42	96%	
3/14/2011	29.04	7.21	7.16	5.04	31.84	9.62	7.70	87.02	93.44	0%	High NOx at the stack exhaust was due to a plugged urea injection lance (Note 4).
3/15/2011	28.24	6.44	7.60	2.99	29.70	7.59	8.40	92.96	101.85	98%	
3/16/2011	28.44	6.31	8.23	3.16	30.97	7.93	8.93	102.24	112.00	0%	
3/17/2011	29.40	8.59	8.11	2.34	31.30	10.76	8.56	102.10	107.70	0%	High NOx at the stack exhaust was due to a plugged urea injection lance (Note 4).
3/18/2011	29.51	8.20	8.84	2.54	31.79	11.09	32.82	102.78	110.18	98%	
3/19/2011	29.74	8.35	8.26	1.65	30.91	9.75	8.78	104.74	110.34	98%	
3/20/2011	27.83	6.94	7.72	1.31	30.84	9.39	8.77	93.75	104.95	95%	
3/21/2011	28.21	7.40	7.07	1.89	32.24	11.51	7.72	86.26	93.65	96%	
3/22/2011	29.87	8.50	7.62	2.62	33.20	11.89	8.58	97.16	108.53	98%	High NOx at the stack exhaust was due to adjustments to the SCR system by the system vendor (Note 3).
3/23/2011	29.24	7.54	8.08	1.31	31.75	9.71	8.65	101.83	108.03	98%	
3/24/2011	30.65	8.85	7.80	1.82	33.25	11.38	8.64	104.13	111.30	98%	
3/25/2011	30.25	8.63	8.04	2.64	31.35	10.14	28.89	105.44	111.08	98%	
3/26/2011	29.18	7.42	7.68	1.61	31.17	9.73	8.31	102.28	109.88	97%	
3/27/2011	27.38	6.34	7.25	1.56	30.41	9.39	8.12	91.24	100.63	96%	
3/28/2011	28.92	7.97	6.98	1.78	30.98	9.74	7.51	91.25	100.68	98%	
3/29/2011	28.50	7.37	7.33	1.65	30.23	9.67	7.97	95.03	105.40	98%	
3/30/2011	29.35	8.24	7.90	2.25	31.85	11.35	8.37	103.55	110.65	98%	
3/31/2011	29.44	8.39	8.09	2.01	30.77	10.27	8.43	106.76	111.47	98%	

Notes:

(1) Urea injection setpoints were modified on June 8, 2010. Therefore, stack exhaust NOx data prior to June 8, 2010 is not included in the analysis of the SCR system and is not provided in this table.
(2) The first 30 minutes after start-up of the engine are excempt from Amended Rule 1110.2. Data was excluded where NOx at the stack exhaust exceeded 11 ppmvd during engine start-up.
(3) Data was excluded where NOx at the stack exhaust exceeded 11 due to system adjustments to the urea injection system.
(4) Data was excluded where operational issues occurred from 7/1/10-7/4/10, 12/29/10-1/4/11, 3/14/11, 3/17/11, and 3/22/11.
(5) Values shown are average or maximum values (as indicated) for each calendar day and may not all occur at the same time within the day.
(6) N/A indicates that data was not available because the engine was offline.

APPENDIX C-4:

Technical Memorandum:
OCSD Catalytic Oxidizer/SCR Pilot Study:
Ammonia Sampling and Calculation Methods

Technical Memorandum

Date: July 31, 2011

To: File

From: Kit Liang ; Daniel Stepner, Malcolm Pirnie, WHI

Re: OCSD Cat Ox/SCR Pilot Study: Ammonia Sampling and Calculation Methods

Project No.: 0788-187

Introduction

To meet the South Coast Air Quality Management District (SCAQMD) Rule 1110.2 limit for oxides of nitrogen (NOx), the Orange County Sanitation District (OCSD) installed a urea-based selective catalytic reduction (SCR) system after the internal combustion (IC) engine exhaust and catalytic oxidizer (Cat Ox) at the Plant 1 Engine 1. The SCR system was designed to remove NOx through a chemical reaction between ammonia (provided by the urea ($(NH_2)_2CO$)) and the NOx on the SCR catalyst surface. During this process, a small amount of unreacted free ammonia (NH_3) or "*ammonia slip*" can be emitted into the exhaust gas. The objective of this memorandum is to discuss the reactions leading to ammonia slip, and a comparison of the different ammonia estimation methods.

SCR Overview

SCR is an air pollution control method that reduces the NOx emissions resulting from fossil fuel combustion through a chemical reaction between the NOx in the exhaust stream and NH_3 provided by the injection of ammonia or urea. The reaction is facilitated by a catalyst to form nitrogen and water vapor.

Engine 1 at OCSD Plant 1 is a four-stroke cycle engine, fueled with a blend of digester gas and natural gas. A Johnson Matthey® SCR system is located downstream of the engine and after a catalytic oxidizer. Aqueous urea is injected into the engine exhaust duct upstream of the SCR catalyst. Once urea is injected into the engine exhaust stream, it breaks down into ammonia and other constituents. Hydrolysis of the urea on the face of the catalyst generates more ammonia. This ammonia reagent reacts with the NOx in the stack emissions, and with the aid of a catalyst, reduces the NOx to harmless constituents: nitrogen, water vapor, and carbon dioxide. The ammonia can also react with sulfur dioxide (SO_2) and sulfur trioxide (SO_3) in secondary reactions to produce ammonium bisulfate (NH_4HSO_4) and ammonium sulfate ($(NH_4)_2SO_4$). The equations for these reactions are as follows:

Urea Reaction

$(NH_2)_2CO \rightarrow NH_3 + HNCO$

$HNCO + NOx + O_2 \rightarrow N_2 + H_2O + CO_2$

Ammonia Reaction
$NH_3 + NOx + O_2 \rightarrow N_2 + H_2O + CO_2$

Secondary Reactions:
$2SO_2 + O_2 \rightarrow 2SO_3$
$2NH_3 + SO_3 + H_2O \rightarrow (NH_4)_2SO_4$
$NH_3 + SO_3 + H_2O \rightarrow NH_4HSO_4$

The ammonia/NOx reaction is optimal between 750°F and 850°F. The amount of NOx in the engine exhaust gas varies with the engine load, and fuel type or fuel blend (in this case, the proportion of digester gas and natural gas). In the SCR system, the injection of the urea is controlled based on process variables, including engine operation (on/off), engine load (i.e., process flow), and NOx concentration measured at the exhaust stack; and the quantity of urea to be injected is roughly proportional to the NOx being reduced and the volume of exhaust flow.

It is important not to inject more urea than necessary in order to keep the unreacted, unconsumed, free ammonia levels to a minimum. Excess free ammonia can occur when:

- Ammonia or urea, is over-injected into the exhaust stream,
- The temperature of the gas is too low for the ammonia to react, or
- The catalyst is degraded.

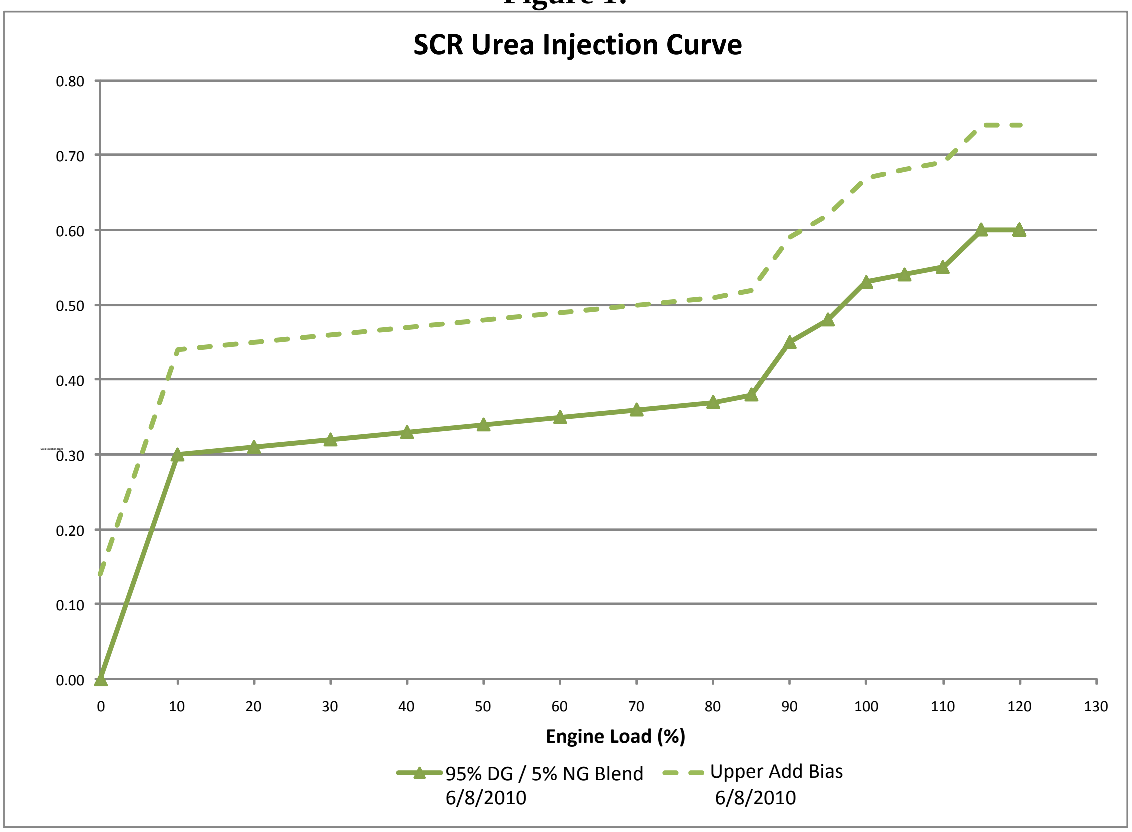
Significantly high levels of free ammonia in the exhaust stack gases can often be identified by a visible plume above the stack. Not only can the excess ammonia exceed permitted limits (ammonia is regulated by SCAQMD), but it also indicates that more ammonia or urea than needed was injected, resulting in a greater urea supply and storage capacity than actually needed to control the NOx emissions. In addition, compounds such as the sulfates formed in the secondary reactions presented above, in which free ammonia reacts with sulfur compounds, have been shown to result in the corrosion of downstream equipment and to cause line plugging. This has been discussed in the literature in particular for fuels with high sulfur content, such as coal. The general range of temperatures for the sulfate formation is reported to range from 390 to 450 ºF for medium to low sulfur fuels.

Johnson Matthey® SCR Urea Control System
The goal of the SCR control system is to balance urea injection to reduce NOx concentration in the exhaust gas to below 11 ppm with a minimum amount of unconsumed or free ammonia. The maximum concentration of free ammonia allowed for this Pilot Study Research Permit is 10 ppm NH_3.

The urea injection control system determines the correct rate of urea according to the engine load signal and the urea versus engine load map programmed into the control system. The load map, which correlates the urea injection rate to the engine load, was programmed during commissioning of the system by Johnson Matthey®. This load map allows the controller to interpolate between the prescribed load values and urea injection rate to generate an overall curve of urea injection vs. engine load. As the engine is brought to load and as the engine load changes, urea flow rate is modulated by the flow control valve according to the determined urea injection rate. In addition to the load map control, the injection system also receives the NOx concentration at the stack outlet from the continuous emissions monitoring system (CEMS) stack exhaust NOx probe. This NOx signal is then used to increase the actual urea injection rate by a set percent *bias* as needed in order to fine tune the NOx emission rate.

As the engine was operated under varying loads during load mapping, Johnson Matthey® measured the NOx concentration with a portable chemiluminescent analyzer and the ammonia slip with Draeger® tubes at the SCR catalyst outlet. The purpose of these measurements was to develop a plot (map) of urea injection rate versus engine load that would meet NOx and ammonia slip emissions requirements. The urea injection rate versus engine load map is provided in Figure 1 below. The solid line represents the true set points for urea injection rate based on engine load set by Johnson Matthey® on June 8, 2010. The dashed line represents the urea injection rate with the injection rate bias to increase the urea injection rate based on the NOx outlet emissions.

Figure 1:



Methods of Estimating Ammonia Concentration

Three methods were used for determining ammonia concentration:

- On-site field measurement using Draeger® or Sensidyne® tubes (free ammonia),
- SCAQMD Method 207.1 (free ammonia), and
- Estimated total ammonia calculation method using inlet and outlet NOx CEMS concentration and urea injection rate.

Draeger® and Sensidyne® Tubes

Free ammonia was measured in the field periodically using Draeger® and Sensidyne® tubes. A Draeger® or Sensidyne® tube is a glass vial filled with a chemical reagent that reacts and changes color in the present of a targeted chemical. When a gas is pumped through the tube, the discoloration of the reagent is read against a scale on the outside of the tube to indicate the concentration of the chemical.

During the field sampling, a Tedlar® bag was filled with exhaust gas from the sample port located after the SCR outlet. The exhaust gas was pulled through the Draeger® or Sensidyne® tube; and the concentration of free ammonia was read against the scale on the tube. Two ranges of Draeger® tubes were used to detect ammonia: 0.25-3 ppm (low-scale) and 2-30 ppm (high-scale). If ammonia was detected and saturated the low-scale tube, the high-scale tube was used.

Estimated Ammonia Calculation Method

Using the estimated ammonia calculation formula, total ammonia is calculated based on the NOx inlet and NOx outlet concentrations, urea injection rate, and total exhaust flowrate. Data from the CEMS system and operational data from the data acquisition system (DAS) were used for the calculations. The NOx and urea react on a 1:2 basis. Therefore, the amount of urea reacted is theoretically equal to two times the amount of NOx reduced by the SCR.

$$Ammonia = \left[Urea\ Fed - \frac{NOx\ in - NOx\ out}{2}\right] \times CF$$

The CEMS vendor, Cemtek Environmental, Inc., programmed the following formula to calculate ammonia slip:

$$Ammonia = \left[\frac{(2 \times \rho \times Urea\ Flow\ Rate \times \%\ wt\ urea)}{Urea\ Molecular\ Weight} - \frac{Dry\ Gas\ Flow\ Rate}{29} \times \frac{(NOx\ in - NOx\ out)}{10^6}\right] \times \frac{10^6}{Dry\ Gas\ Flow\ Rate/29} \times CF$$

The *Dry Gas Flow Rate* is calculated using the following equation:

$$Dry\ Gas\ Flow\ Rate = \big((Fuel\ Flow\ \times Fuel\ GCV) \times Fuel\ Factor\big) \times (20.9/(20.9 - \%\ O2)$$

Where the following units apply:

- *Urea Flow Rate*: gallon per hour (gal/hr)
- *NOx in*, *NOx out* (inlet and outlet NOx concentration): parts per million (ppm_c) @ 15% O_2
- *Dry Gas Flow Rate*: pounds per hour (lbs/hr)
- *CF*: Correction factor (derived annually)
- *Fuel Flow Rate*: dry standard cubic feet of fuel (dscf)
- *Fuel GCV* (gas constant value): Btu value of the fuel / dscf
- *Fuel Factor*: dscf @ 0% O_2 / million Btu value of the fuel
- $\rho\left(\frac{H2O}{Urea}\right) = 68.9\frac{lb}{ft^3}\, or\ 9.21\frac{lb}{gal}\ \ with\ urea\ @\ 32.5\%\ wt\ @\ 4°C$
- $Urea\ Molecular\ Weight = 60.0553\frac{lb}{lb}mol$

The estimated ammonia calculation method allows for adjustment of the ammonia estimation through use of the correction factor, CF. Without accounting for secondary reactions through consumption of free ammonia with other compounds in the engine exhaust gas, such as sulfates, the method actually estimates total ammonia (i.e., free ammonia plus combined ammonia). The method does allow for use of a correction factor which could be applied to account for these secondary reactions. During the pilot test, no correction factor for potential side reactions was programmed into the calculation, and the CF was assumed equal to 1.

SCAQMD Method 207.1

SCAQMD Method 207.1 is the regulatory approved method for determining free ammonia emissions from stationary sources. This method is a wet chemistry method in which the samples are collected from impingers containing a sulfuric acid solution. The samples are then analyzed by an ion selective electrode.

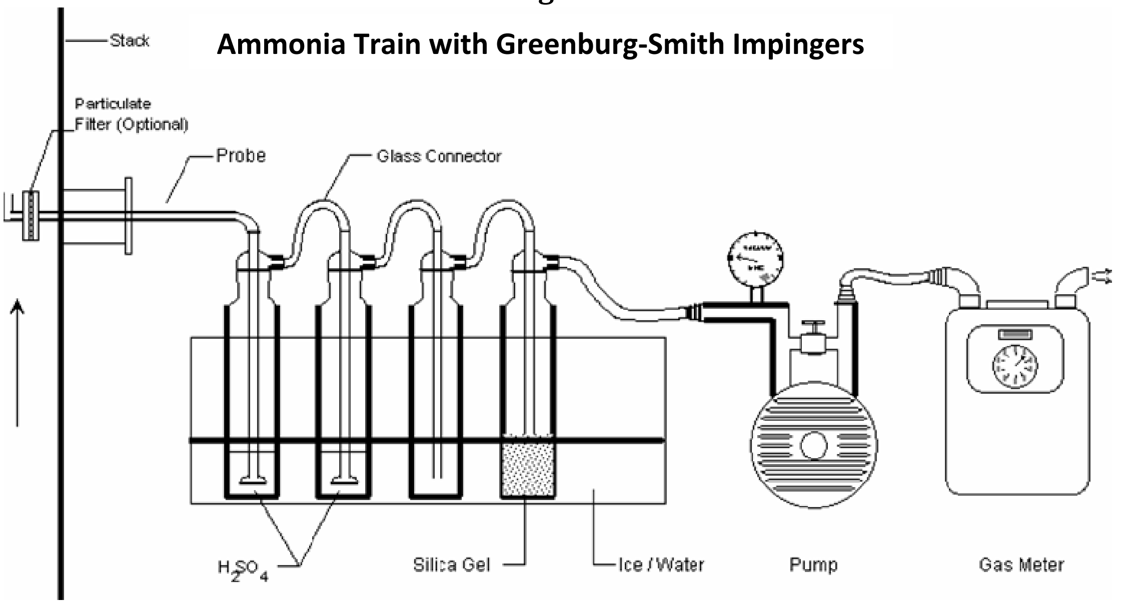
Figure 2 provides a standard setup for the SCAQMD Method 207.1. During the initial period of the pilot testing, the testing firm, SCEC, performed ammonia sampling at the stack exhaust for three loads on April 7 and 8, 2010.

Discussion

Table 1 presents a comparison of the free ammonia concentrations determined using the Draeger® and Sensidyne® tubes, the free ammonia concentrations determined using SCAQMD Method 207.1, and the theoretical total ammonia calculations. The ammonia concentration values were based on the same recorded 15-minute average CEMS data for all three methods.

While the field measurements taken with the Draeger® and Sensidyne® tubes show no measurable free ammonia, the total ammonia calculation method based on the CEMS data did provide a calculated value of total ammonia (free plus combined ammonia). Likewise, the results using SCAQMD Method 207.1 on 4/7/2010, 4/8/2010, and 5/10/2011 were less than 1 ppm of free ammonia, while the estimated total ammonia method calculated values using the CEMS data were noticeably higher.

Figure 2:



Ammonia Train with Greenburg-Smith Impingers

The ammonia calculation method is dependent on the NOx inlet and NOx outlet concentrations, and the urea injection rate, which is continuously changing based on the engine load and the NOx outlet concentration. The difference between the estimated total ammonia calculation method and the other techniques may be due to the conservative nature of the estimated method for determining ammonia slip, since it assumes that the ammonia from the urea consumes only NOx. There is the potential for ammonia molecules to also be consumed in other secondary reactions in the exhaust stream, such as those with sulfur compounds (forming combined ammonia). However, no correction factors were applied to account for the consumption of ammonia in secondary reactions. Without a correction factor to account for these secondary reactions, the calculation method essentially estimates total ammonia, or the sum of free and combined ammonia.

Engine load fluctuates with time. When the IC engines are set to a base load, it was observed that the actual engine load fluctuated rapidly by as much as ten percent below the set point. This was found to be typical for the OCSD IC engines. However, since urea injection rate is mapped to engine load, rapid fluctuations in load can result in rapid changes in urea injection rates. Rapidly changing urea injection rates, instead of steady rates with smooth transitions, can also lead to inaccuracies in the ammonia calculation.

Table 1:
Ammonia Concentration Sampling Event Summary

Date	Engine Load	Draeger® and Sensidyne® Tube (Free Ammonia) (ppmv) [1]	Calculated Value (Total Ammonia) (ppmv) [2]	SCAQMD Method 207.1 (Free Ammonia) (ppmv)
4/7/2010 & 4/8/2010	65%	<MDL	1.66	0.12
	90%			0.18
	105%			0.43
4/21/2010	110%	<MDL	0.09	N/A
4/29/2010	90%	<MDL	0.00	N/A
5/6/2010	94%	<MDL	2.18	N/A
5/19/2010	100%	<MDL	2.54	N/A
6/29/2010	100%	<MDL	0.97	N/A
7/28/2010	100%	<MDL	0.63	N/A
8/12/2010	95%	<MDL	2.50	N/A
11/4/2010	100%	<MDL	4.95	N/A
1/12/2011	100%	<MDL	0.32	N/A
2/24/2011	100%	<MDL	0.09	N/A
5/10/2011	70%	<MDL	1.12	0.37
	90%		1.60	0.31
	110%		3.12	0.38

Notes:
1. Free ammonia field measurements were taken at the SCR outlet using 0.25-3 ppm range and 2-30 ppm range Draeger® tubes. On 5/10/2011, additional free ammonia field measurements were taken at the stack exhaust using Sensidyne® tubes with the same measurement results as the Draeger® tubes.
2. Total ammonia was determined based on the theoretical calculation which uses NOx inlet and NOx outlet of the Cat Ox/SCR system and the urea injection rate. The calculated value reported is based on the 15-minute block average from the CEMS for the time period when the exhaust gas sample was taken for the field measurement. No correction factor was applied.
3. <MDL – less than Method Detection Limit.
4. N/A indicates not applicable. No data was taken using Method 207.1 during these field measurement events.

Conclusions and Recommendations

Upon review of the field measurements for free ammonia and calculated values for total ammonia, the estimated total ammonia calculation method appears to overestimate the free ammonia in the SCR outlet over both the field sampling method and SCAQMD Method 207.1. This may be partially due to the varying urea injection rates. In addition, the estimated ammonia calculation method does not account for other potential ammonia reactions which may consume the unreacted ammonia, such as those with sulfur compounds in the exhaust gas. Without the application of a correction factor to account for these, the calculation method actually estimates total ammonia (free plus combined ammonia). However, this may be useful as a tool to prompt a field measurement to confirm free ammonia concentrations in the exhaust gases. Additional sampling of the exhaust emissions could be performed to establish a correction factor for the theoretical ammonia slip calculation method. The presence of sulfur dioxide and sulfur trioxide in the exhaust gas before the SCR, and ammonium sulfate and ammonia bisulfate detected in the exhaust gas after the SCR, can indicate that secondary reactions are taking place due to the injection of urea.

Further study is needed to determine the potential for detrimental effects of ammonia sulfates formation in equipment downstream of the SCR system. For example, after two years of Engine 1 operation using the Cat Ox/SCR system with DGCS, it is recommended that OCSD examine the heat recovery boiler for any equipment deterioration or noticeable particulate buildup.

Although little, if any, free ammonia was found during the pilot study of the SCR system, it is recommended that the OCSD perform additional and routine testing for free ammonia during varying loads and fuel blends over a period of time. Additional testing for free ammonia can provide data to verify that the SCR system does not produce ammonia slip from the stack exhaust under the range of operating conditions for a given mapped urea injection versus engine load set point.

References

Johnson Matthey. "*SCR Control System Description, Malcolm Pirnie/Orange County Sanitation District*." January 2010.

Cemtek, Environmental, Inc. Letter to Malcolm Pirnie. Re: NH3 Slip Calculation. 25 March 2010.

Falk, David. "*Ammonium Sulphate Deactiviation of SCR DeNOx Catalysts*," Department of Chemical Engineering, Lund Instituted of Technology, Jan. 2007: 1-7.

REFERENCES

1. Orange County Sanitation District, *Catalytic Oxidizer Pilot Study*, Report to AQMD, August 2007

2. Orange County Sanitation District, *Retrofit Digester Gas Engine with Fuel Gas Clean-up and Exhaust Emission Control Technology*, Final Report to AQMD, July 2011

3. SCAQMD, 2008. *Staff Report: Proposed Amended Rule 1110.2 - Emissions From Gaseous- and Liquid-Fueled Engines*. South Coast Air Quality Management District, February 2008

4. SCAQMD, 2008. *Staff Report: Proposed Amended Rule 1110.2 - Emissions From Gaseous- and Liquid-Fueled Engines*. South Coast Air Quality Management District, February 2008, Appendix D

5. E. Wheless, D. Gary, *Siloxanes in Landfill and Digester Gas*, Proceedings of Solid Waste Association of North America (SWANA) Landfill Gas Symposium, March 2002

6. SCAQMD, 2010. *Interim Report on Technology Assessment for Biogas Engines Subject to Rule 1110.2*. South Coast Air Quality Management District, July, 2010

7. E.P.A, *Compilation of Air Pollutant Emission Factors (AP-42, Volume 1, Stationary Point and Area Sources)*, http://www.epa.gov/ttnchie1/ap42/, accessed February 10, 2012

8. Mark Fulton, Nils Mellquist, Saya Kitasei, and Joel Bluestein, *Comparing Life-Cycle Greenhouse Emissions from Natural Gas and Coal*, Deutsche Bank Group, Worldwatch Institute and ICF International (August 25, 2011), http://www.worldwatch.org/system/files/pdf/ Natural_Gas_LCA_Update_082511.pdf, accessed February 10, 2012

9. SCAQMD, *BACT Guidelines*, http://www.aqmd.gov/bact/index.html, accessed February 10, 2012

10. Financial Energy Management, Inc, *Reciprocating Combustion Engine and Generator Set*, http://www.financialenergy.com/services/generator/types.htm, accessed March 2012.

11. California Public Utilities Commission, *Self-Generation Incentive Program Handbook*, October 10, 2011, http://www.cpuc.ca.gov/PUC/energy/DistGen/sgip/.

ATTACHMENT H

SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT

Final~~Draft~~ Socioeconomic Assessment for
Proposed Amendments to Rule 1110.2–Emissions from Gaseous- and Liquid-Fueled Internal Combustion Engines

January 2008~~November 2007~~

Executive Officer
Barry R. Wallerstein, D.Env.

Deputy Executive Officer
Planning, Rule Development & Area Sources
Elaine Chang, DrPH

Assistant Deputy Executive Officer
Planning, Rule Development & Area Sources
Laki T. Tisopulos, Ph.D., P.E.

Author: Patricia Kwon, Air Quality Specialist

Reviewed By: Martin Kay, Program Supervisor
Sue Lieu, Program Supervisor
Jill Whynot, Director, Strategic Initiatives
Mike Harris, Senior Deputy District Counsel
Barbara Baird, Principal Deputy District Counsel

SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT
GOVERNING BOARD

Chair: WILLIAM A. BURKE, Ed.D.
Speaker of the Assembly Appointee

Vice Chair: S. ROY WILSON, Ed.D.
Supervisor, Fourth District
Riverside County Representative

MEMBERS:

MICHAEL D. ANTONOVICH
Supervisor, Fifth District
Los Angeles County Representative

BILL CAMPBELL
Supervisor, Third District
Orange County Representative

JANE W. CARNEY
Senate Rules Committee Appointee

RONALD O. LOVERIDGE
Mayor, City of Riverside
Cities Representative, Riverside County

GARY OVITT
Supervisor, Fourth District
San Bernardino County Representative

JAN PERRY
Councilmember, 9th District
Cities Representative, Los Angeles County, Western Region

MIGUEL PULIDO
Mayor, City of Santa Ana
Cities Representative, Orange County

TONIA REYES-URANGA
Councilmember, City of Long Beach
Cities Representative, Los Angeles County, Eastern Region

JOSEPH K. LYOU, Ph.D.
Governor's Appointee

DENNIS YATES
Mayor, City of Chino
Cities Representative, San Bernardino County

EXECUTIVE OFFICER:
BARRY R. WALLERSTEIN, D.Env.

EXECUTIVE SUMMARY

A socioeconomic analysis was conducted to assess the impacts of the proposed amendments to Rule 1110.2–Emissions from Gaseous-and Liquid-Fueled Internal Combustion Engines–and the alternatives for the proposed amendments identified in the Draft Environmental Assessment. A summary of the analysis and findings are presented below.

Elements of Proposed Rule Amendments	The proposed amendments to Rule 1110.2 will require stationary, non-emergency engines to meet emission standards equivalent to current Best Available Control Technology (BACT) for natural gas engines in the next 3-5 years, which partially implements the 2007 AQMP control measure MCS-001 Facility Modernization; increase the source testing, continuous monitoring, and inspection and maintenance (I&M) and reporting~~monitoring (I&M)~~ requirements to improve rule compliance; require new electrical generating engines to meet standards that are at or near the CARB 2007 Distribution Generation Emission Standards, which require ~~the same~~ emissions ~~limits as~~ equivalent to large central power plants; and clarify the status of portable engines. Before biogas engines are required to comply with more stringent standards in 2012, staff will conduct a technology assessment to assure that the promising new technologies that have become available are feasible and cost-effective. The proposed amendments are projected to result in emission reductions of 2.2 tpd NOx, 0.69 tpd of VOC and 19 tpd CO.
Affected Facilities and Industries	The proposed amendments to Rule 1110.2 will affect 405 facilities with 859 active internal combustion engines, of which 178 facilities are in Los Angeles County, 96 are in Orange County, 78 are in Riverside County, and 53 are in San Bernardino County. These facilities belong to a wide range of industries. Approximately half (47%) of the facilities belong to the utilities sector (NAICS 221) and another 10% each belong to the industries of oil and gas extraction (NAICS 211) and government (NAICS 92).
Assumptions of Analysis	Facilities subject to Rule 1110.2 were surveyed in 2005 with data collected on 631 out of 859 active engines (74% response rate). To reflect the total number of active engines in the AQMD permit database, scaling factors for each engine type were used to re-align the survey data. Daily inspections are assumed to be performed by the facilities. Source testing, parametric monitoring and emission checks are assumed to be performed by testing

	laboratories except for facilities with more than one engine which would perform their own parametric monitoring and emission checks. It is assumed that facilities with more than one engine would perform their own CEMS maintenance while facilities with a single engine would contract maintenance with the equipment vendor. Based on the current technology, it is assumed that facilities have to install biogas cleanup systems, selective catalytic reduction system (SCR), and OC, or other equivalent technology by 2012. It is assumed that biogas engine maintenance would be performed by staff at the affected facilities. The life of all devices required for compliance with the proposed requirements is assumed to be 10 years. Catalysts are assumed to be installed and maintained by equipment vendors and will be replaced every three years.
Compliance Costs	Changes to the proposed amendments since the release of the Draft Socioeconomic Report have not significantly changed compliance cost. Overall, costs for all the affected industries ranged from $10.76 million in 2008 to $27.24 million in 2012, with an average annual cost of $22.39 million between 2008 and 2020. Costs vary significantly by industry with the majority of the cost in the utility industry (NAICS 221) with an average annual cost of $11.53 million between 2008 and 2020. This is followed by the waste management and remediation services industry (NAICS 562) with an average annual cost of $2.86 million between 2008 and 2020. Source testing and I&M requirements impact 614 engines at the affected facilities, followed by the requirements for new emission limits (333), and increased continuous monitoring requirements (83 engines to install CEMS, 48 engines to install CO analyzers, and 40 engines to install AFRC). However, the requirement of new emission limits would result in the highest compliance cost, an average annual cost of $11.0 million between 2008 and 2020. A technology assessment will be conducted by rule staff in 2010 to evaluate new available technologies that are feasible and cost-effective. One possible technology for biogas engines is the NOxTech system which requires no catalyst or fuel treatment that will be tested by Eastern Municipal Water District. It is expected to be more cost-effective than the technology currently proposed.

Jobs and Other Socioeconomic Impacts	Overall, 169 jobs could be forgone annually, on average, between 2008 and 2020 in the local economy. Additional job growth was projected in the professional, scientific, and technical services sector (NAICS 54) with 45 jobs gained and in the machinery manufacturing sector (NAICS 333) with 5 jobs gained. These job gains are due to an increased demand for source testing and specialized equipment to meet the lower emission limits. The industries with the greatest jobs forgone annually between 2008 and 2020 primarily are construction (NAICS 23) with 30 jobs forgone, other services (NAICS 81) with 26 jobs forgone, local and state government (NAICS 92) with 25 jobs forgone, and retail trade (NAICS 44-45) with 23 jobs forgone.
Competitiveness	The sectors of utilities (NAICS 221), oil and gas extraction (NAICS 211), and administrative and waste services (NAICS 56) would experience the largest increases in the relative cost of production and relative delivered price in 2012. These sectors also incur the highest average annual compliance costs among all private sectors. In 2020 increases in the relative cost of production and relative delivered price in these sectors are decreasing. All the remaining sectors will experience a smaller magnitude of increase in production cost and relative delivered price due to the proposed amendments.
Impacts of CEQA Alternatives	There are four CEQA alternatives associated with the proposed amendments to Rule 1110.2. Alternative A is the No Project Alternative, which is the existing Rule 1110.2. Alternative B—Expansion of Low Use Exemption—would increase the low usage exemption for non-biogas engines. Alternative C—Compliance Improvement Only—would only require increased source testing and I&M, and the installation of AFRC, CO analyzers, and CEMS. Alternative D—Engine Electrification—would give biogas engines that are less than 10 years old an additional two years to comply, eliminate the low-use exemption in the proposed amendments, and require mandatory electrification of selected engines. Average annual compliance costs for the CEQA alternatives range from \$11.4 to \$29.5 million between 2008 and 2020. Jobs forgone for the CEQA alternatives range from 89 jobs to 273 jobs. CEQA Alternative D has the highest average annual cost and job impacts of all the CEQA alternatives, with an average annual cost of \$29.5 million and 273 jobs forgone between 2008 and 2020.

INTRODUCTION

The proposed amendments to Rule 1110.2 will:

- Require stationary, non-emergency engines to meet emission standards equivalent to current Best Available Control Technology (BACT) for natural gas engines in the next 3-5 years, which partially implements the 2007 AQMP control measure MCS-001 Facility Modernization;
- Increase the source testing, continuous monitoring, and inspection and maintenance (I&M) and reporting~~monitoring (I&M)~~ requirements to improve rule compliance;
- Require new electrical generating engines to meet standards that are at or near the CARB 2007 Distribution Generation Emission Standards, which require ~~the same~~ emissions ~~limits as~~ equivalent to large central power plants;
- ~~and~~ Clarify the status of portable engines.

Before biogas engines are required to comply with more stringent standards in 2012, staff will conduct a technology assessment to assure that the promising new technologies that have become available are feasible and cost-effective.

Because more than half of stationary non-emergency engines are in RECLAIM or already have BACT emission limits, the emission reductions from the proposed amendments are significant, but not as large as one might expect. The proposed amendments are projected to result in emission reductions of 2.2 tpd NOx, 0.69 tpd of VOC and 19 tpd CO. The socioeconomic analysis examines the impact of the proposed amendments and the alternatives identified in the Draft Environmental Assessment.

The proposed amendments also address non-compliance of engines with emissions limits due to poor operating and maintenance procedures and inadequate monitoring required by the existing rule. They also achieve additional emission reductions for the 2007 Air Quality Management Plan to meet the more stringent federal ozone and particulate matter standards. The United States Environmental Protection Agency (EPA) has thus raised SIP approvability issues about the Rule 1110.2 source testing and monitoring requirements. The proposed amendments may incentivize voluntary electrification of selected engines in order to reduce compliance costs (i.e., avoiding more frequent maintenance or source testing, or meeting new emission limits), which has a co-benefit of reducing CO_2 emissions.

REGULATORY HISTORY

Rule 1110.2 was adopted in August 1990 to require the replacement of non-utility internal combustion engines (ICEs) with electric motors. An annual compliance cost was estimated at $156.7 million. Utility sponsored programs that promoted the electrification of ICEs were expected to reduce the compliance cost.

This rule has subsequently been amended five times. There were administrative changes and clarifications for the rule amendments in August 1994 and December 1994, with no socioeconomic impacts. In November 1997 requirements for portable engines were revised to be consistent with federal and state regulations. In addition, the continuous emission monitoring requirements for CO were removed and source testing was reduced from annually to every three years. This amendment was projected to result in a potential cost savings for owners/operators of stationary engines and all portable engines except those in the 50- to 100-bhp size class. Those engines requiring retrofitting would incur a cost of $0.089 - $0.459 million annually, depending on the control option chosen.

In June 2005 stationary agricultural engines were required to comply with the rule by replacing their engines with a controlled spark ignition engine and non-selective catalytic reduction system (NSCR) or an electric motor, or adding an NSCR to an existing spark ignition engine. The total annual cost of the proposed amendments was estimated at $0.316 million annually. With available state funding, the net cost to agricultural facilities was reduced to $0.004 million annually.

LEGISLATIVE MANDATES

The socioeconomic assessments at the AQMD have evolved over time to reflect the benefits and costs of regulations. The legal mandates directly related to the assessment of the proposed amendments include the AQMD Governing Board resolutions and various sections of the California Health & Safety Code (H&SC).

AQMD Governing Board Resolutions

On March 17, 1989 the AQMD Governing Board adopted a resolution that calls for preparing an economic analysis of each proposed rule for the following elements:

- Affected Industries
- Range of Control Costs
- Cost Effectiveness
- Public Health Benefits

On October 14, 1994, the Board passed a resolution which directed staff to address whether the rules or amendments brought to the Board for adoption are in the order of cost effectiveness as defined in the AQMP. The intent was to bring forth those rules that are cost effective first.

Health & Safety Code Requirements

The state legislature adopted legislation that reinforces and expands the Governing Board resolutions for socioeconomic assessments. H&SC Sections 40440.8(a) and (b), which became effective on January 1, 1991, require that a socioeconomic analysis be prepared for any proposed rule or rule amendment that *"will significantly affect air quality or emissions limitations."* Specifically, the scope of the analysis should include:

- Type of Affected Industries
- Impact on Employment and the Economy of the district
- Range of Probable Costs, Including Those to Industries
- Emission Reduction Potential

- Necessity of Adopting, Amending or Repealing the Rule in Order to Attain State and Federal Ambient Air Quality Standards
- Availability and Cost Effectiveness of Alternatives to the Rule

Additionally, the AQMD is required to actively consider the socioeconomic impacts of regulations and make a good faith effort to minimize adverse socioeconomic impacts. H&SC Section 40728.5, which became effective on January 1, 1992, requires the AQMD to:

- Examine the type of industries affected, including small businesses; and
- Consider Socioeconomic Impacts in Rule Adoption

H&SC Section 40920.6, which became effective on January 1, 1996, requires that incremental cost effectiveness be performed for a proposed rule or amendment relating to ozone, carbon monoxide (CO), oxides of sulfur (SO_x), oxides of nitrogen (NO_x), and their precursors. Incremental cost effectiveness is defined as the difference in costs divided by the difference in emission reductions between one level of control and the next more stringent control.

AFFECTED FACILITIES

The proposed amendments to Rule 1110.2 will affect 405 facilities with 859 active internal combustion engines, of which 178 facilities are in Los Angeles County, 96 are in Orange County, 78 are in Riverside County, and 53 are in San Bernardino County. These facilities belong to a wide range of industries. Approximately half (47%) of the facilities belong to the utilities sector (NAICS 221) and another 10% each belong to the industries of oil and gas extraction (NAICS 211) and government (NAICS 92).

Small Businesses

The AQMD defines a "small business" in Rule 102 as one which employs 10 or fewer persons and which earns less than $500,000 in gross annual receipts. In addition to the AQMD's definition of a small business, the federal Small Business Administration (SBA), the federal Clean Air Act Amendments (CAAA) of 1990, and the California Department of Health Services (DHS) also provide definitions of a small business.

The SBA's definition of a small business uses the criteria of gross annual receipts (ranging from $0.5 million to $25 million), number of employees (ranging from 100 to 1,500), or assets ($100 million), depending on industry type. The SBA definitions of small businesses vary by 6-digit NAICS code.

The CAAA classifies a facility as a "small business stationary source" if it: (1) employs 100 or fewer employees, (2) does not emit more than 10 tons per year of either VOC or NOx, and (3) is a small business as defined by SBA.

Dun and Bradstreet financial data on individual facilities for total revenue and total number of employees was available for 339 out of 405 facilities. Under the AQMD definition of a small business, there are 44 small businesses. Using the SBA definition of a small business, there are 160 small businesses. Under the CAAA definition of a small business, 80 are small businesses.

COMPLIANCE COST

Changes to the proposed amendments since the release of the Draft Socioeconomic Report have not significantly changed compliance cost. Under the proposed amendments, affected facilities are subject to increased source testing and I&M requirements, increased continuous monitoring requirements, and new emission limits. The affected engines can be divided into biogas and non-biogas fueled engines that are lean-burn or rich-burn engines. Some of these engines are regulated under the AQMD's RECLAIM program. Proposed requirements are the same for both biogas and non-biogas engines except for compliance dates for the new emission limits, and emission limits for new electrical generators.
Facilities subject to Rule 1110.2 were surveyed in 2005 with data collected on 631 out of 859 active engines (74% response rate). To reflect the total number of active engines in the AQMD permit database, scaling factors for each engine type were used to re-align the survey data. The scaling factors are provided in Appendix H of the Rule 1110.2 Staff Report.

Costs for the proposed requirements are divided into equipment, other capital, and annual costs. Equipment costs include the purchase, installation, and testing of equipment. Other capital costs include one-time AQMD fees, plans and protocols, and testing not associated with equipment. Annual costs include ongoing expenses such as testing, AQMD fees, maintenance labor, and replacement of equipment parts. The life of all devices required for compliance with the proposed requirements is assumed to be 10 years.

Source Testing, Inspection, and Monitoring

The majority of engines will be subject to increased source testing and I&M requirements in 2008. However, engines used less than 2,000 hours in three years would not be required to perform additional source testing and engines monitored by a NOx and CO continuous emission monitoring system (CEMS) would not be required to develop and implement an I&M plan. Equipment necessary to comply with the source testing and I&M requirement includes alarms and portable analyzers. Other capital costs associated with the implementation of source testing and I&M requirements include the development of a facility I&M plan and source testing protocol, baseline source and parametric testing, and AQMD evaluation fees. Annual costs include source and parametric testing, emission checks using portable analyzers, daily inspections, and AQMD fees charged twice every thirteen months for review of the source test protocol and the source test report. Equipment and annual operating costs vary by engine type. Rich burn engines will have the highest annual operating costs since they will require weekly or monthly emission checks and daily parametric monitoring. Lean burn RECLAIM engines require only quarterly emissions checks and hence have the lowest annual operating costs. Daily inspections are assumed to be performed by the facilities. Source testing, parametric monitoring and emission checks are assumed to be performed by testing laboratories except for facilities with more than one engine which would perform their own parametric monitoring and emission checks. [1] Table 1 shows a range of these cost categories.

Continuous Monitoring

Compliance with continuous monitoring requirements require the installation of additional CEMS, air-to-fuel ratio controllers (AFRC), or CO analyzers to engines in 2009-2011. CEMS is required on a group of engines at the same location with a total horsepower of ≥1500 hp and using $\geq 16\times10^{9}$ Btu/yr (not including engines <500 hp, standby engines, engines used <1000 hrs/yr, or engines using $<8\times10^{9}$ Btu/yr). Equipment costs of CEMS include equipment, data acquisition system, installation, certification testing, startup and training. Other capital costs include AQMD fees. Annual costs include replacement of span gases, relative accuracy test audit (RATA) testing, and CEMS maintenance. Facilities with multiple engines connected to a CEMS incur additional equipment ($35,000) and annual ($15,000) costs for each additional engine attached to the CEMS. These additional costs include one-time installation and sampling system equipment costs, and span gas and RATA testing annual costs. It is assumed that facilities with more than one engine would perform their own CEMS maintenance while facilities with a single engine would contract maintenance with the equipment vendor. Equipment costs for single-engine CEMS installations range from $168,600 to $176,600.

Engines without CEMS are required to install an AFRC. CO analyzers are required to be added on rich burn engines with an existing NOx CEMS. AFRC costs include equipment costs for equipment and annual costs for the quarterly replacement of oxygen sensors. CO analyzer costs include equipment costs for equipment. CO analyzer annual costs are assumed to be minimal since little additional span gases or RATA testing is required. AFRC ($20,000) and CO analyzer equipment costs ($19,000) are the same for all engine types.

New Emission Limits

Facilities with non-biogas engines that do not have current BACT and are used more than 500 hours or burn more than 1000 MMBtu annually are required to install catalysts to comply with new emission limits in 2010 and 2011. Oxidation catalysts (OC) are required for lean burn RECLAIM engines. Rich burn engines not at the BACT level must upgrade their existing three way catalyst (TWC). Equipment costs for both types of catalysts include equipment and installation. Other capital costs include AQMD permit fees. Annual costs include catalyst replacement. Equipment costs vary by engine size with a range from $14,858 to $54,876. Catalysts are assumed to be installed and maintained by equipment vendors, and replaced every three years.

Biogas engines that are used more than 500 hours or burn more than 1,000 MMBtu annually are subject to new emission limits and required to meet the same emission limits as natural gas fueled engines. Based on the current technology, it is assumed that facilities have to install biogas cleanup systems, selective catalytic reduction system (SCR), and OC, or other equivalent technology by 2012. Equipment costs for biogas cleanup systems, SCR, and OC include

[1] In addition, facilities with multiple engines and maintenance staff will likely purchase portable analyzers and conduct their own emission checks and daily monitoring since this is the most economical option.

equipment, installation, and performance tests. Other capital costs include AQMD permit fees. Annual costs include periodic sorbent tests, sorbent disposal and replacement, catalyst replacement for SCR and OC, additional electricity due to the parasitic load on the engine, and annual maintenance on parts. It is assumed that biogas engine maintenance would be performed by staff at the affected facilities. Equipment costs for the biogas cleanup system, SCR, and OC range from $271,909 to $744,793.

Table 1 shows the unit costs for the proposed requirements including equipment, other capital, and annual costs. Additional information on unit costs is presented in Appendix H of the Rule 1110.2 Staff Report.

Table 1
Unit Costs by Proposed Requirement (in dollars)

Proposed Requirements/Control Devices			**Engine Type**			
Source Testing and I&M	**Compliance Year**	**Type of Cost**	**Lean burn**	**Rich burn**	**Lean burn RECLAIM**	**Facility >1 Engine**
Alarms, portable analyzers, source testing, I&M	2008	Equipment Other Capital Annual	$240 3,189 10,468	$240 3,189 15,348	$240 3,189 6,268	$10,240 3,189 10,468
Continuous Monitoring	**Compliance Year**	**Type of Cost**	**Lean burn**	**Rich burn**	**Lean burn RECLAIM**	**Facility >1 Engine**
CEMS	2009-2011	Equipment Other Capital Annual	168,600 4,000 35,000	176,600 4,000 35,000	N/A	35,000 0 15,000
AFRC	2009	Equipment Annual	20,000 720			
CO analyzers	2010-2011	Equipment	19,000			
New Emission Limits	**Compliance Year**	**Type of Cost**	**0-499 hp**	**500-999 hp**	**1000+ hp**	
Lean-Burn OC	2010-2011	Equipment Other Capital Annual	11,880 2,300 1,833	15,312 2,300 2,405	30,765 2,300 4,981	
Rich-burn TWC	2010-2011	Equipment Other Capital Annual	14,858 2,300 4,659	24,010 2,300 7,710	54,876 2,300 17,999	
			0-1499 hp	**1500+ hp**		
Biogas cleanup systems, SCR, OC	2012	Equipment Other Capital Annual	271,909 6,300 $56,445	744,793 6,300 $166,331		

I&M is inspection and maintenance; CEMS is continuous emission monitoring system; AFRC is air-to-fuel ratio controllers; OC is oxidation catalyst; TWC is three way catalyst; and SCR is selective catalytic reduction system.

Source testing and I&M requirements impact 614 engines at the affected facilities, followed by the requirements for new emission limits (333), and increased continuous monitoring requirements (83 engines to install CEMS, 48 engines to install CO analyzers, and 40 engines to install AFRC). However, the requirements of new emission limits will result in the highest average annual compliance cost of $11.0 million between 2008 and 2020. Costs by proposed requirement are shown in Table 2.

Table 2
Costs by Proposed Requirement (in millions of dollars)

Proposed Requirement	2008	2012	2020	Average Annual (2008-2020)
Source testing, I&M	$10.8	$8.8	$8.8	$9.0
Continuous monitoring	0.0	3.0	3.0	2.5
New emission limits	0.0	15.5	15.4	11.0
TOTAL	$10.8	$27.2	$27.1	$22.4

A technology assessment will be conducted by rule staff in 2010 to evaluate new available technologies that are feasible and cost-effective. One possible technology for biogas engines is the NOxTech system which requires no catalyst or fuel treatment that will be tested by Eastern Municipal Water District. It is expected to be more cost-effective than the technology currently proposed.

Overall, costs for all the affected industries ranged from $10.76 million in 2008 to $27.24 million in 2012, with an average annual cost of $22.39 million between 2008 and 2020. Costs vary significantly by industry with the majority of the cost in the utility industry (NAICS 221) with an average annual cost of $11.53 million between 2008 and 2020. This is followed by the waste management and remediation services industry (NAICS 562) with an average annual cost of $2.86 million between 2008 and 2020. These costs correspond with the implementation of source testing and I&M requirements beginning in 2008, non-biogas engine compliance requirements in 2010 and 2011, and biogas engine compliance requirements in 2012. The cost by industry (NAICS) is shown in Table 3.

Table 3
Average Annual Compliance Costs by Industry (in million of dollars)

Industry Title	NAICS Code	2008	2012	2020	Average Annual (2008-2020)
Oil, gas extraction	211	$0.52	$1.11	$1.11	$1.04
Utilities[1]	221	5.31	14.36	14.24	11.53
Food manufacturing	311	0.28	0.23	0.23	0.23
Textile product mills manufacturing	314	0.07	0.06	0.06	0.06
Wood product manufacturing	321	0.02	0.03	0.13	0.06
Paper manufacturing	322	0.00	0.04	0.04	0.03
Printing, related support services	323	0.02	0.03	0.03	0.03
Petroleum, coal products manufacturing	324	0.03	0.06	0.06	0.06
Chemical manufacturing	325	0.02	0.02	0.02	0.02
Plastics, rubber product manufacturing	326	0.09	0.20	0.20	0.18
Nonmetallic mineral product manufacturing	327	0.01	0.02	0.02	0.04
Primary metal manufacturing	331	0.14	0.16	0.17	0.16
Fabricated metal product manufacturing	332	0.02	0.02	0.02	0.02
Computer, electronic product manufacturing	334	0.02	0.02	0.02	0.02
Wholesale trade	42	0.11	0.49	0.49	0.40
Retail trade	44	0.02	0.03	0.03	0.03
Truck transportation	484	0.00	0.01	0.01	0.01
Transit and ground passenger transportation	485	0.06	0.45	0.45	0.38
Pipeline transportation	486	0.37	0.68	0.68	0.66
Warehousing and storage	493	0.02	0.02	0.02	0.02
Credit intermediation and related activities	522	0.00	0.10	0.10	0.09
Insurance carriers and related activities	524	0.02	0.02	0.02	0.02
Funds, trusts, and other financial vehicles	525	0.07	0.06	0.06	0.06
Real estate	531	0.12	0.10	0.10	0.10
Professional, scientific, technical services	541	0.27	0.79	0.77	0.63
Administrative and support services	561	0.14	0.12	0.12	0.12
Waste management, remediation services[1]	562	0.05	4.28	4.08	2.86
Educational services	611	0.28	0.43	0.43	0.40
Hospitals	622	0.36	0.58	0.58	0.55
Nursing and residential care facilities	623	0.06	0.07	0.08	0.07
Performing arts, spectator sports, and related industries	711	0.05	0.04	0.04	0.04
Amusement, gambling and recreation industries	713	0.48	0.51	0.52	0.50
Accommodation	721	0.42	0.46	0.46	0.45
Repair and maintenance	811	0.02	0.02	0.02	0.02
Religious, grantmaking, civic, professional, and Similar Organizations	813	0.14	0.12	0.12	0.12
Government	92	1.15	1.54	1.60	1.42
TOTAL		**$10.76**	**$27.24**	**$27.12**	**$22.39**

[1]The utilities sector provides services in electric power, natural gas, steam supply, water supply, and sewage removal while the waste management and remediation services sector is involved in the collection, treatment, and disposal of waste materials.

JOBS AND OTHER SOCIOECONOMIC IMPACTS

The REMI model (version 9.0.3) is used to assess the total socioeconomic impacts of a policy change. The model links the economic activities in the counties of Los Angeles, Orange, Riverside, and San Bernardino. The REMI model for each county is comprised of a five block structure that includes (1) output and demand, (2) labor and capital, (3) population and labor force, (4) wages, prices and costs, and (5) market shares. These five blocks are interrelated. Within each county, producers are made up of 66 private non-farm industries, three government sectors, and a farm sector. Trade flows are captured between sectors and borders as well as across counties and the rest of U.S. Market shares of industries are dependent upon their product prices, access to production inputs, and local infrastructure. The demographic/migration component has 160 ages/gender/race/ethnicity cohorts and captures population changes in births, deaths, and migration.

The assessment herein is performed relative to a baseline of the existing Rule 1110.2. Direct effects of the policy change (proposed amendments) have to be estimated and used as inputs to the REMI model in order for the model to assess secondary and induced impacts for all the actors in the four-county economy on an annual basis and across a user-defined horizon. Direct effects of PAR 1110.2 include additional costs of proposed requirements to affected industries and additional sales of control devices by local vendors at the county (or finer) level and by industry.

The proposed amendments would create an additional demand for the services of testing laboratories (NAICS 541) such as source and parametric testing and emission checks due to the source testing requirements, RATA tests on CEMS for the monitoring requirements, and performance and sorbent tests for biogas cleanup systems for meeting the new emission limits. There would be additional demand for the products in the industrial machinery manufacturing sector (NAICS 333) due to the purchase, installation, and maintenance of OC, TWC, SCR, and biogas cleanup systems for meeting the new emission limits. Additional demand would be created for instruments for controlling industrial process variables (NAICS 334) due to the purchase, installation, and maintenance of alarms and portable analyzers for source testing and CEMS, AFRC, and CO analyzers for monitoring requirements. Lastly, there would be additional demand in the chemical manufacturing sector (NAICS 325) for span gases used in the operation of CEMS for monitoring requirements and in utilities (NAICS 221) for electricity from the parasitic load on biogas engines from installing biogas cleanup systems and catalysts.

Costs for capital equipment including alarms and portable analyzers for source testing requirements; CEMS, AFRC, CO analyzers for monitoring requirements; and OC, TWC, biogas cleanup systems/SCR/OC for meeting the new emission limits were annualized at the 4-percent real interest rate as the additional cost of doing business to the affected facilities. For the government sector, this is modeled as a decrease in government spending elsewhere. There will be additional labor required for source testing and I&M requirements (I&M plan, daily inspections, emission checks, and source testing); CEMS maintenance for monitoring requirements; and biogas cleanup system and SCR maintenance (routine maintenance and replacement of parts), for biogas engines for meeting the new emission limits. The additional labor requirement would result in reduced labor productivity for affected businesses. One-time

AQMD permit and evaluation fees for the installation of new or modified equipment and the evaluation of I&M plans and source testing protocols are an additional cost of doing business for the affected facilities and represent an increase in demand by local governments on the other hand.

Overall, 169 jobs could be forgone annually between 2008 and 2020 in the local economy. This represents on average 0.0016 percent of total estimated jobs in the four-county region between 2008 and 2020. The machinery manufacturing sector is only 40% value added while the professional, scientific, and technical services is 70% value added which means that additional demand in these sectors will create greater job impacts in the professional, scientific, and technical services sector.

The industry sectors with the greatest jobs forgone annually between 2008 and 2020 are primarily construction (NAICS 23) with 30 jobs forgone, other services (NAICS 81) with 26 jobs forgone, local and state government (NAICS 92) with 25 jobs forgone, and retail trade (NAICS 44-45) with 23 jobs forgone. Despite having the highest compliance cost, the capital-intensive utility sector is projected to have minimal jobs forgone. However, construction activities represent a significant input for the utility sector. The reduction in output of the utility sector would thus have a relatively large impact on the labor-intensive construction sector. The costs incurred by biogas facilities in the public sector could result in jobs forgone in local and state government. Jobs forgone in the other services and retail trade sectors are due to a drop in real disposable income, which reduces consumption in these areas. Job growth was projected in the professional, scientific, and technical services sector (NAICS 54) with 45 jobs gained and in the machinery manufacturing sector (NAICS 333) with 5 jobs gained. These job gains are due to an increased demand for source testing and specialized equipment to meet the lower emission limits. Table 4 presents estimated job impacts by industry for the proposed amendments.

Table 4
Job Impacts by Industry

Industry	(NAICS)	2008	2012	2020	Average Annual (2008-2020)
Oil, gas extraction	211	0	-1	-2	-1
Utilities	221	0	-2	-4	-3
Construction	23	-7	-25	-40	-30
Food manufacturing	311	0	-1	-2	-2
Apparel manufacturing	315	0	0	-1	0
Wood product manufacturing	321	0	-1	-1	-1
Paper manufacturing	322	0	0	-1	0
Printing, related support services	323	0	0	-1	-1
Chemical manufacturing	325	0	0	-1	0
Plastics, rubber product manufacturing	326	0	0	-1	-1
Nonmetallic mineral product manufacturing	327	0	0	-1	-1
Primary metal manufacturing	331	0	0	-1	-1
Fabricated metal product manufacturing	332	0	2	-3	-2
Machinery manufacturing	333	0	38	1	5
Motor vehicle manufacturing	3361-3363	0	0	-1	-1
Transportation equipment manufacturing	3364-3369	0	0	-1	0
Computer, electronic product manufacturing	334	0	-1	-1	-1
Electrical equipment, appliance manufacturing	335	0	0	-1	0
Furniture, related product manufacturing	337	0	-1	-2	-1
Miscellaneous manufacturing	339	0	0	-1	-1
Wholesale trade	42	-1	-2	-11	-7
Retail trade	44-45	-5	-15	-33	-23
Transportation and Warehousing	48-49	-1	-2	-8	-5
Information	51	-2	-4	-7	-5
Finance and Insurance	52	-3	-7	-15	-11
Real Estate and Rental and Leasing	53	-1	-8	-17	-11
Professional, Scientific, Technical Services	54	52	71	33	45
Management of Companies and Enterprises	55	0	1	-3	-2
Administrative and Support and Waste Management and Remediation Services	56	1	-6	-28	-16
Educational services	61	0	-4	-11	-7
Health Care and Social Assistance	62	-1	-4	-19	-11
Arts, Entertainment and Recreation	71	0	-4	-7	-5
Accommodation and Food Services	72	-4	-12	-26	-18
Other Services	81	-10	-26	-34	-26
Local and State Government	92	-14	-21	-40	-25
Total[1]		**1**	**-37**	**-293**	**-169**

[1]The sum of individual numbers may not be the same as the total due to rounding.

Competitiveness

The additional cost brought on by the proposed rule would increase the cost of production of the affected industries relative to their national counterparts. Changes in relative production costs would thus be a good indicator of changes in relative competitiveness. The magnitude of the impact depends on the size and diversification of, and infrastructure in a local economy as well as interactions among industries. A large, diversified, and resourceful economy would absorb the impact with relative ease. Implementation of the proposed amendments to Rule 1110.2 increases the cost of doing business for affected industries.

An index of 0 indicates that there is no change in the cost of production relative to the rest of the United States. An index of above or below 0 means that the cost of production in the four-county areas resulting from the proposed amendments is higher or lower, respectively, than that in the rest of the U.S.

The sectors of utilities (NAICS 221), oil and gas extraction (NAICS 211), and administrative and waste services (NAICS 56) would experience the largest increases in the relative cost of production, as shown in Table 5. The utilities sector would experience an increase of 0.076% in 2012. These sectors also incur the highest average annual compliance costs among all private sectors. In 2020 increases in the relative cost of production in these sectors are decreasing. All the remaining sectors will experience a smaller magnitude of increase in production cost due to the proposed amendments.

Changes in production costs will affect prices of goods produced locally. The relative delivered price of a good is based on its production cost and the transportation cost of delivering the good to where it is consumed or used. The average price of a good at the place of use reflects prices of the good produced locally and imported elsewhere.

Based on the measurement of relative delivered prices in the REMI model, the proposed amendments are projected to result in higher delivered prices. These impacts are similar to those for the relative cost of production. The same industry sectors of utilities (NAICS 221), oil and gas extraction (NAICS 211), and administrative and waste services (NAICS 56) would experience the largest increases in relative delivered prices (Table 5). The utilities sector would experience a 0.0598% increase in relative delivered price in 2012. Increases in relative delivered price are decreasing in 2020. Nearly all other industries will experience a smaller magnitude of increase in relative delivered price.

Table 5
Impacts on Relative Cost of Production and Delivered Prices
(Relative to the U.S.)

Industry	Relative Cost of Production 2012	Relative Cost of Production 2020	Relative Delivered Price 2012	Relative Delivered Price 2020
Forestry, Fishing, Other	0.0006%	0.0005%	0.0002%	0.0001%
Oil and Gas Extraction	0.0213%	0.0177%	0.0068%	0.0056%
Utilities	0.0760%	0.0629%	0.0598%	0.0495%
Construction	0.0006%	0.0007%	0.0006%	0.0007%
Manufacturing	0.0015%	0.0013%	0.0010%	0.0008%
Wholesale Trade	0.0009%	0.0007%	0.0008%	0.0007%
Retail Trade	0.0008%	0.0006%	0.0008%	0.0006%
Transportation and Warehousing	0.0036%	0.0031%	0.0027%	0.0023%
Information	0.0008%	0.0006%	0.0007%	0.0005%
Finance and Insurance	0.0009%	0.0007%	0.0008%	0.0006%
Real Estate, Rental and Leasing	0.0019%	0.0012%	0.0018%	0.0012%
Professional and Technical Services	0.0011%	0.0008%	0.0011%	0.0008%
Management Companies and Enterprises	0.0005%	0.0004%	0.0005%	0.0004%
Administrative and Waste Services	0.0102%	0.0076%	0.0103%	0.0077%
Educational Services	0.0041%	0.0034%	0.0036%	0.0029%
Health Care and Social Assistance	0.0014%	0.0011%	0.0012%	0.0010%
Arts, Entertainment and Recreation	0.0025%	0.0020%	0.0031%	0.0024%
Accommodation and Food Services	0.0020%	0.0016%	0.0014%	0.0011%
Other Services (excluding Government)	0.0013%	0.0011%	0.0013%	0.0010%

CEQA ALTERNATIVES

There are four CEQA alternatives associated with the proposed amendments to Rule 1110.2. Alternative A is the No Project Alternative, which is the existing Rule 1110.2, and would continue the existing emission limits.

Alternative B—Expansion of Low Use Exemption—would increase the low usage exemption for non-biogas engines from the new emission limits to engines used less than 1,000 hours or consuming less than 2,000 MMBtu of electricity annually, allow biogas engines a 1 hour averaging time, and exempt lean-burn engines from installing CEMS. Increasing the low usage exemption for non-biogas engines would result in having fewer CEMS, oxidation catalysts and TWC installed, but would increase the number of AFRCs installed. Alternative B would maintain the same source testing and I&M requirements; and the same number of CO analyzers for non-biogas engines and biogas cleanup systems, SCR, and oxidation catalysts for biogas engines installed as the proposed amendments.

Alternative C—Compliance Improvement Only—would only require increased source testing and I&M, and the installation of AFRC, CO analyzers, and CEMS, compared to the proposed amendments.

Alternative D—Engine Electrification—would give biogas engines that are less than 10 years old an additional two years to comply with the new emission limits, eliminate the low-use exemption in the proposed amendments, reduce the new CO limit from 250 to 70 ppmvd (parts per million per volume), and require mandatory electrification of selected engines that are evaluated to be technically and economically feasible. It would reduce the installation of CEMS, CO analyzers, AFRC, oxidation catalysts, and TWC because engines subject to mandatory electrification would no longer have to install these types of equipment. However, the increased source testing and I&M requirement for all non-electrified engines and the installation of equipment for biogas engines would remain the same as the proposed amendments for engines not subject to electrification. There would be costs associated with mandatory electrification of engines, including engine removal and replacement with an electric motor and increased electricity charges. There would be savings resulting from no longer using natural gas or diesel fuel and reduced maintenance labor cost.

Average annual compliance costs for the CEQA alternatives range from $11.4 to $29.5 million between 2008 and 2020. Jobs forgone for the CEQA alternatives range from 89 jobs to 273 jobs. CEQA Alternative D has the highest average annual cost and job impacts of all the CEQA alternatives, with an average annual cost of $29.5 million and 273 jobs forgone between 2008 and 2020. Some of these additional job losses would be due to the decreased demand for engine repair and maintenance services (NAICS 811) and for natural gas and diesel fuels (NAICS 221) from the mandatory electrification of engines.

Table 6
Cost and Job Impacts of CEQA Alternatives (in millions of dollars)

Alternative	Average Annual (2008-2020)		
	Cost	Cost-Effectiveness $/ton (NOx, VOC, CO)	Jobs
Proposed Amendments	$22.4	$5,651	-169
Alternative A—No Project	0.00	N/A	N/A
Alternative B— Expansion of Low Use Exemption	20.4	$5,879	-148
Alternative C— Compliance Improvement Only	11.4	$3,503	-89
Alternative D—Engine Electrification	$29.5	$5,348~~031~~	-273

RULE ADOPTION RELATIVE TO THE COST-EFFECTIVENESS SCHEDULE

On October 14, 1994, the Governing Board adopted a resolution that requires staff to address whether rules being proposed for adoption are considered in the order of cost-effectiveness. The 2007 Air Quality Management Plan (AQMP) ranked, in the order of cost-effectiveness, all of the proposed control measures for which costs were quantified. It is generally recommended that the most cost-effective actions be taken first. While Rule 1110.2 is not part of a quantified control measure under the 2007 AQMP, it will achieve additional emission reductions required by the 2007 AQMP to meet more stringent federal ozone and particulate matter standards.

REFERENCES

South Coast Air Quality Management District. Governing Board packages for Rule 1110.2 amendments and initial rule adoption. August 1990, September 1990, August 1994, December 1994, November 1997, June 2005.

South Coast Air Quality Management District. Draft Environmental Assessment. Proposed Amended Rule 1110.2. October 2007.

South Coast Air Quality Management District. Draft Staff Report and Rule. Proposed Amended Rule 1110.2. November 2007.

ATTACHMENT I

SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT

Addendum to the 2007 Final Environmental Assessment for Proposed Amended Rule 1110.2 – Emissions from Gaseous - and Liquid-Fueled Engines

August 2012

SCAQMD No. 120817JK

Executive Officer
Barry R. Wallerstein, D. Env.

Deputy Executive Officer
Planning, Rule Development and Area Sources
Elaine Chang, DrPH

Assistant Deputy Executive Officer
Planning, Rule Development and Area Sources
Laki Tisopulos, Ph.D., P.E.

Planning and Rules Manager
Planning, Rule Development and Area Sources
Susan Nakamura

Author:	James Koizumi	Air Quality Specialist
Technical Assistance:	Kevin Orellana	Air Quality Specialist
	Wayne Barcikowski	Air Quality Specialist
Reviewed By:	Steve Smith, Ph.D.	Program Supervisor, CEQA
	Joe Cassmassi	Planning and Rules Manger
	Gary Quinn	Program Supervisor
	William Wong	Principal Deputy District Counsel
	Barbara Baird	District Counsel

SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT
GOVERNING BOARD

CHAIRMAN: WILLIAM A. BURKE, Ed.D.
Speaker of the Assembly Appointee

VICE CHAIR: DENNIS R. YATES
Mayor, City of Chino
Cities Representative, San Bernardino County

MEMBERS:

MICHAEL D. ANTONOVICH
Supervisor, Fifth District
Los Angeles County Representative

JOHN J. BENOIT
Supervisor, Fourth District
Riverside County Representative

MICHAEL A. CACCIOTTI
Mayor, City of South Pasadena
Cities of Los Angeles County, Eastern Region

JOSIE GONZALES
Supervisor, Fifth District
San Bernardino County Representative

RONALD O. LOVERIDGE
Mayor, City of Riverside
Cities Representative, Riverside County

JOSEPH K. LYOU, Ph.D.
Governor's Appointee

JUDITH MITCHELL
Councilmember, Rolling Hills Estates
Cities of Los Angeles County, Western Region

SHAWN NELSON
Supervisor, Fourth District
Orange County Representative

CLARK E. PARKER, Ph.D.
Senate Rules Committee Appointee

JAN PERRY
Councilwoman, Ninth District
City of Los Angeles Representative

MIGUEL A. PULIDO
Mayor, City of Santa Ana
Cities Representative, Orange County

EXECUTIVE OFFICER:
BARRY R. WALLERSTEIN, D.Env.

TABLE OF CONTENTS

INTRODUCTION

The California Legislature created the South Coast Air Quality Management District (SCAQMD) in 1977[1] as the agency responsible for developing and enforcing air pollution control rules and regulations in the South Coast Air Basin (Basin) and portions of the Salton Sea Air Basin and Mojave Desert Air Basin referred to herein as the district. The 2007 AQMP concluded that major reductions in emissions of particulate matter (PM), oxides of sulfur (SOx) and oxides of nitrogen (NOx) are necessary to attain the state and national ambient air quality standards for ozone, particulate matter with an aerodynamic diameter of 10 microns or less (PM10) and particulate matter with an aerodynamic diameter of 2.5 microns or less (PM2.5). More emphasis is placed on NOx and SOx emission reductions because they provide greater ozone and PM emission reduction benefits than volatile organic compound (VOC) emission reductions. VOC emission reductions, along with NOx emission reductions, continue to be necessary, because emission reductions of both of these ozone precursors are necessary to meet the ozone standards.

Existing Rule 1110.2 - Emissions from Gaseous- and Liquid-Fueled Internal Combustion Engines, regulates NOx, carbon monoxide (CO), and volatile organic compound (VOC) emissions from stationary and portable engines in the district producing more than 50 rated brake horsepower (bhp). It was originally adopted in 1990 and amended in 2008 to implement, in part, the 2007 AQMP Control Measure MCS-01 – Facility Modernization.

The currently proposed amendments would make effective certain limits already adopted and analyzed in a California Environmental Quality Act (CEQA) document for the amendments to Rule 1110.2 adopted in 2008, which established new exhaust emission concentration limits for landfill and digester gas-fired engines to take effect July 1, 2012. These limits did not take effect because they were contingent upon completion of a technology assessment by July 2010. Except for CO, the emission standards would be equivalent to the current best available control technology (BACT) for NOx and VOC for new internal combustion engines. Among the engines affected by the 2008 amendments were approximately 55 engines that are fired by landfill or digester gas (biogas), located at 13 public and private landfills and wastewater treatment plants.

Subsequent to the 2008 amendments, Rule 1110.2 was last amended in 2010 to exempt public safety communications engines located at remote sites. The currently proposed amendments would have no effect on the provisions added to Rule 1110.2 in 2010, so this Addendum does not need to consider the 2010 amendments to Rule 1110.2 further.

The adopting resolution for the 2008 amendments to Rule 1110.2 directed staff to conduct a technology assessment before July 2010 to address the feasibility of achieving the July 1, 2012 compliance limits for biogas-fueled engines. However, the permit moratorium in 2009 caused a delay in the startup of demonstration projects designed to test whether or not the final compliance limits were feasible. Because of this delay, SCAQMD staff presented an *Interim Report on the Technology Assessment for Rule 1110.2 Biogas Engines* to the Governing Board in July 2010. The interim report pointed to two potential technologies that were being evaluated in the continuing demonstration projects that were part of the technology demonstration. One demonstration project has since been completed, but the other demonstration project's startup

[1] The Lewis-Presley Air Quality Management Act, 1976 Cal. Stats., ch 324 (codified at Health & Safety Code, §§40400-40540).

has been affected by other unforeseen delays. Given the delays in completing the demonstration projects at that time, the Interim Technology Assessment mentioned the possible necessity of an adjustment to the July 1, 2012 effective date to allow additional time for the completion of the technology assessment.

The proposed amendments would:

- Allow biogas facility operators/owners three and a half to six additional years to comply with the emission limits that did not take effect. The new effective date would be January 1, 2016. Permit application fees would be refunded to biogas-fueled engines owner/operators who establish to the satisfaction of the Executive Officer that they havecomplied with the emission limits of Table III-B by January 1, 2015. Owners or operators of biogas-fired units that operate under long term fixed price power purchage agreements that have been entered into prior to February 1, 2008, and extend beyond January 1, 2016 may elect to defer compliance by up to two additional years and no later than January 1, 2018 provided that they submit an alternative compliance plan and pay a compliance flexibility fee. The compliance flexibility fees associated with the alternative compliance plan would be applied to SCAQMD NOx reduction programs pursuant to protocols approved under SCAQMD rules.
- Provide a compliance option with a longer averaging time, provided that the engine operator can demonstrate through continuous emission monitoring systems (CEMS) that emissions are at least 9.9 ppmv for NOx and 225 ppmv for CO.

The proposed amendments are described in more detail in the "Project Description" section below and in Appendix A to this Addendum.

SCAQMD staff has met with stakeholders and the affected community to discuss the feasibility and cost effectiveness of the control technologies expected to be used to comply with the biogas-fueled engine requirements of Rule 1110.2. SCAQMD staff has also met individually with most affected facility operators to discuss site-specific issues relative to complying with the proposed emission limits for biogas-fueled engines. These discussions are ongoing.

CALIFORNIA ENVIRONMENTAL QUALITY ACT

The proposed amendments to Rule 1110.2 are considered to be a "project" as defined by the California Environmental Quality Act (CEQA). CEQA requires that the potential adverse environmental impacts of proposed projects be evaluated and that feasible methods to reduce or avoid significant adverse environmental impacts of these projects be identified. To fulfill the purpose and intent of CEQA, the SCAQMD, as the CEQA Lead Agency for the proposed project has prepared this Addendum to the 2007 Final Environmental Assessment for Proposed Amended Rule 1110.2 - Emissions from Gaseous- and Liquid-Fueled Internal Combustion Engines (SCAQMD No. 280307JK, December 2007) (2007 Final EA) adopted February 1, 2008, which included an evaluation of environmental impacts from amending Rule 1110.2, cumulative impacts, project alternatives, and all other applicable CEQA requirements.

Analysis of the proposed project indicated that an Addendum to the 2007 Final EA prepared pursuant to CEQA Guidelines §15164 is the appropriate CEQA document for this project, because SCAQMD staff has concluded that the proposed amendments only result in some changes or additions to the 2007 Final EA that do not trigger the conditions described in CEQA Guidelines §15162 calling for preparation of a subsequent EIR:

1. No substantial changes are proposed in the project which required major revision of the previous CEQA document due to the involvement of new significant environmental effects or a substantial increase in the severity of previously identified significant effects; or
2. No substantial changes would occur with respect to the circumstances under which the project is undertaken which will require major revisions of the previous CEQA document due to the involvement of new significant environmental effects or a substantial increase in the severity of previously identified significant effects; or
3. No new information of substantial importance, which was not known and could not have been known with the exercise of reasonable diligence at the time the previous CEQA document was certified as complete shows any of the following:
   A. One or more significant effects not discussed in the previous CEQA document;
   B. Significant effects previously examined with be substantially more severe than shown in the previous CEQA document;
   C. Mitigation measures or alternatives previously found not to be feasible would be in fact feasible, and would substantially reduce one or more significant effects of the project, but the project proponents decline to adopt the migration measure or alternative; or
   D. Mitigation measures or alternatives which are considerably different from those analyzed in the previous EIR would substantially reduce one or more significant effects on the environment, but the project proponents decline to adopt the migration measure or alternative.

Based on the analysis in this addendum, PAR 1110.2 would not generate new significant environmental effects or a substantial increase in the severity of previously identified significant effects. Since PAR 1110.2 would not generate new significant environmental effects or as substantial increase in the severity of previously identified significant effects, no new mitigation measures or alternatives have been proposed. No changes to existing mitigation measures or alternatives are proposed. This conclusion is supported by substantial evidence provided as part of the environmental analysis in this Addendum and other documents in the record.

Thus this Addendum, prepared pursuant to CEQA Guidelines §15164, focuses on the topic of air quality and GHG emissions, specifically operational air quality impacts. Although the currently proposed project would delay the final compliance limits for biogas engines, this proposal is not considered a rule relaxation for the following reasons. The 2008 amendments to Rule 1110.2 included a provision that the emission limits for biogas-fueled engines would only become effective provided that SCAQMD staff conducts a technology assessment and reports to the Governing Board by July 2010. Because the technology assessment was not completed by July 2010, the emission limits for biogas engines are not considered to be in effect.

The analysis of these potential environmental impacts did not identify any significant adverse environmental impacts, including operational air quality impacts, or make worse any previously identified significant adverse impacts from the 2007 Final EA. Thus, an Addendum to the 2007 Final EA is considered to be the appropriate CEQA document for the proposed project. In addition, pursuant to CEQA Guidelines §15252(a)(2)(B), no project alternatives or mitigation measures are proposed. Prior to making a decision on the proposed amendments to Rule 1110.2, the SCAQMD Governing Board must review this Addendum along with the 2007 Final EA.

PROJECT LOCATION

The SCAQMD has jurisdiction over an area of 10,473 square miles (referred to hereafter as the district), consisting of the four-county South Coast Air Basin and the Riverside County portions of the Salton Sea Air Basin (SSAB) and the Mojave Desert Air Basin (MDAB). The Basin, which is a subarea of the SCAQMD's jurisdiction, is bounded by the Pacific Ocean to the west and the San Gabriel, San Bernardino, and San Jacinto Mountains to the north and east. The 6,745 square-mile Basin includes all of Orange County and the nondesert portions of Los Angeles, Riverside, and San Bernardino counties. The Riverside County portion of the SSAB and MDAB is bounded by the San Jacinto Mountains in the west and spans eastward up to the Palo Verde Valley. The federal nonattainment area (known as the Coachella Valley Planning Area) is a subregion of both Riverside County and the SSAB and is bounded by the San Jacinto Mountains to the west and the eastern boundary of the Coachella Valley to the east (Figure 1).

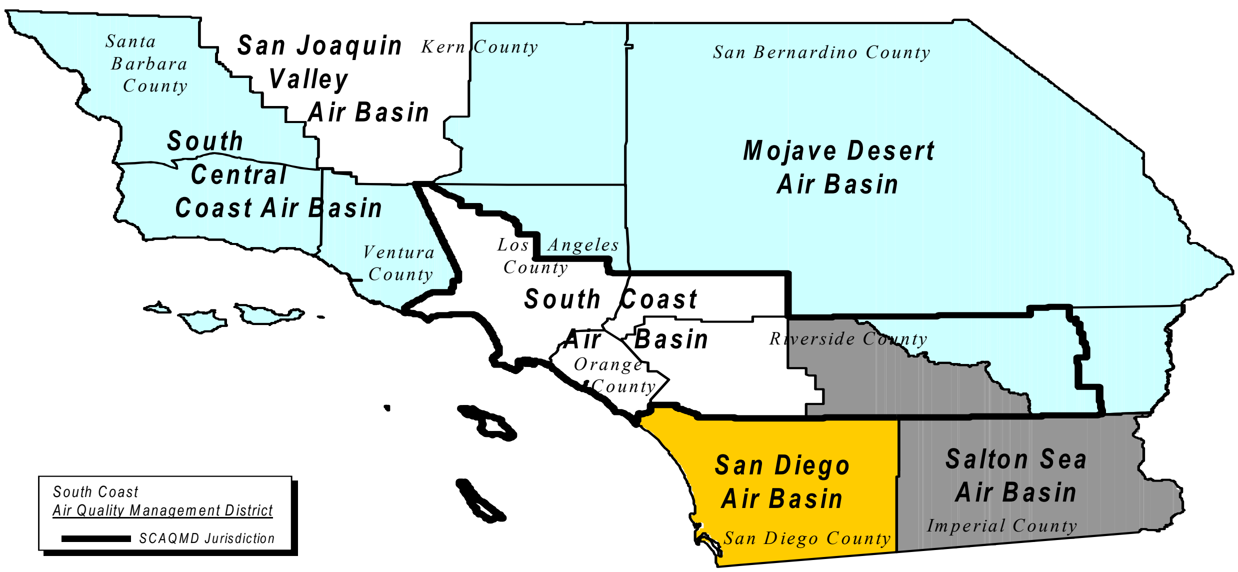


Figure 1
Boundaries of the South Coast Air Quality Management District

PROJECT OBJECTIVES

One of the original project objectives of the 2008 amendments to Rule 1110.2 analyzed in the 2007 Final EA was to achieve NOx emission reductions from affected equipment through imposing control requirements close to BACT in effect at that time, contingent upon a technology assessment presented to the Governing Board in July 2010. A final technology assessment was not available in July 2010, so the original project objective needs to be amended to allow an additional time for biogas-fueled engines to comply with the final biogas-fueled engine emission concentration limits in the existing rule that have been verified a final technology assessment. PAR 1110.2 would continue to adhere to this objective, but allow additional time for operators at facilities with biogas-fueled engines to comply with the proposed biogas concentration limits. Further, the results of OCSD's pilot study shows greater flexibility in complying with the final NOx emission limits is necessary. To this end, to facilitate achieving the above objective, PAR 1110.2 would provide greater flexibility in demonstrating compliance with the final NOx emission limits by extending the compliance testing averaging time.

PROJECT BACKGROUND – BIOGAS-FUELED ENGINES

Rule 1110.2 applies to stationary and portable reciprocating internal combustion engines (ICEs) over 50 brake horsepower (bhp); therefore, Rule 1110.2 regulates biogas-fueled engines. Biogas-fueled engines are engines that operate at landfills and wastewater treatment plants. Biogas-fueled engines are lean-burn engines that operate similarly to lean-burn natural gas-fired engines.

Biogas is generated from the breakdown of municipal solid waste at landfills. Biogas from landfills is primarily composed of methane, carbon dioxide, and contaminants such as siloxane and hydrogen sulfide (H2S). The gas is collected in a series of wells and transported by pipeline to treatment facilities where it is filtered, dewatered, and compressed prior being combusted in the landfill-gas fired engines. Depending on the volume and methane content of the landfill gas collected, it can be used to fuel one or more biogas-fueled engines. If the methane content of the landfill gas is relatively low or the volume collected is low, natural gas, may be used as a supplemental fuel to increase the heat content of the digester gas.

Biogas is also generated at wastewater treatment facilities in digesters. A digester is a process unit in which sewage is broken down by bacteria in a heated oxygen-free (anaerobic) environment. A by-product of this process is biogas that contains methane, CO2, and small amounts of H2S. The treatment of biogas may include removal of components including hydrogen sulfide, water, carbon dioxide, trace organics, and particulates. This digester gas can typically fuel one or more biogas-fueled engines. Natural gas may be used as a supplemental fuel to increase the heat content of the landfill gas.

Biogas-fueled engines are typically used to produce electricity. Some owner/operators use the biogas-generated electricity to provide power for their facility. Other owner/operators sell the biogas-generated power to local electric utility providers. Wastewater treatment plants are typically operated by public entities and utility providers, while the landfills are operated by either public or private operators.

Approximately 66 biogas-fueled engines with SCAQMD permits were identified in the 2010 Interim Technology Assessment. Since that time, some biogas-fueled engines have been removed from service, so the number of biogas-fueled engines remaining at the beginning of the PAR 1110.2 development process has decreased to 55. These 55 engines are located at 22 public and private landfills and wastewater treatment plants under the ownership of 13 operators. These biogas-fueled engines are among the top NOx emitters among stationary, non-emergency engines. As shown in Table 1, based on annual reporting data from 2010, 13 of the top 25 NOx emitters are stationary, non-emergency engines at biogas facilities.

Table 1
"Top 25" Facilities with Highest NOx Emissions from Stationary, Non-Emergency Engines (Pounds per Year) in 2010

Facility	ID No.	NOx	ROG	CO	Fuel(s)
U.S. Govt, Dept Of Navy	800263	110,713	8,967	24,390	Diesel
U.S. Govt, Dept Of Navy	800263	80,714	9,701	26,387	Diesel
Exxonmobil Oil Corporation	800089	69,961	5,594	15,215	Diesel
La County Sanitation District-Puente Hills	***25070***	***52,796***	***18,068***	***284,104***	***Landfill Gas***
Orange County Sanitation District	***29110***	***48,912***	***68,945***	***611,663***	***Digester Gas***
Orange County Sanitation District	***17301***	***41,478***	***43,767***	***426,682***	***Digester Gas***
U.S. Govt, Dept Of Navy	800263	38,469	3,827	10,408	Diesel
Crimson Resource Management	142517	38,093	507	64,119	Natural Gas (Rich-Burn)
Mm Lopez Energy Llc	***104806***	***35,662***	***10,707***	***142,482***	***Landfill Gas***
Mm Prima Deshecha Energy, LLC	***117297***	***32,599***	***6,321***	***127,325***	***Landfill Gas***
Mm Prima Deshecha Energy, LLC	***117297***	***31,474***	***14,005***	***141,724***	***Landfill Gas***
Exxonmobil Oil Corporation	800089	28,192	2,254	6,131	Diesel
Mm Lopez Energy LLC	***104806***	***28,189***	***11,753***	***110,606***	***Landfill Gas***
U.S. Govt, Dept Of Navy	800263	21,923	2,181	5,931	Diesel
Eop - 10960 Wilshire LLC	119133	20,083	267	33,805	Natural Gas (Rich-Burn)
Hollywood Park Land Company LLC	145829	19,792	1,583	4,304	Diesel
Samuel P Lewis Dba Chino Welding & Assem	150351	19,542	260	32,894	Natural Gas (Rich-Burn)
Toyon Landfill Gas Conversion LLC	***142417***	***18,000***	***9,991***	***100,575***	***Landfill Gas***
Orange, County Of - Sheriff Dept, Fac Op	72525	17,314	499	1,344	Natural Gas (Lean-Burn)
Brea Parent 2007, LLC	***113518***	***17,033***	***1,099***	***4,555***	***Landfill Gas***
Huntington Beach City, Water Dept	20231	15,370	205	25,871	Natural Gas (Rich-Burn)
Brea Parent 2007, LLC	***113518***	***15,346***	***784***	***3,140***	***Landfill Gas***
Brea Parent 2007, LLC	***113518***	***14,181***	***1,052***	***4,958***	***Landfill Gas***
Waste Mgmt Disp & Recy Servs Inc (Bradley)	***50310***	***13,934***	***3,465***	***60,087***	***Landfill Gas***
Waste Mgmt Disp & Recy Servs Inc (Bradley)	***50310***	***13,839***	***3,823***	***67,514***	***Landfill Gas***
Totals, pound per year		843,607	229,624	2,336,216	
Totals, ton per year		422	115	1,168	
Totals, ton per day		1.16	0.31	3.20	

PROJECT DESCRIPTION

The following is a summary of the proposed amendments to Rule 1110.2. A copy of PAR 1110.2 can be found in Appendix A.

Subdivision (a) - Purpose

No change.

Subdivision (b) - Applicability

No change.

Subdivision (c) - Definitions

The typo "by" is corrected to "be" in the useful heat recovered definition.

Subdivision (d) - Requirements

- Requirement (d)(1)(B) would be clarified to read "The operator of any stationary engine not covered by (d)(1)(A) and not exempt from this rule shall..."
- Table III would be split into two tables. The concentration limits in Table III that became effective when the 2008 amendments were adopted would become Table IIIA. The concentrations in Table III labeled effective July 1, 2012 would become Table III-B. The effective date for those concentration limits would be changed from July 1, 2012, to January 1, 2016.
- Table III-A or B would be added to the existing Table II in the prohibition not to exceed applicable emissions concentration limits in (d)(1)(B)(ii), so the phrase "notwithstanding the provisions in subparagraph (d)(1)(B)" would be removed in (d)(1)(C).
- The existing reference to Table III in (d)(1)(C) would be changed to Table III-A, since Table III-A would be split into Table III-A and Table III-B.
- "The concentration limits effective on and after July 1, 2012 shall become effective provided the Executive Officer conducts a technology assessment that confirms that the limits are achievable, and reports to the Governing Board by July 2010, at a regularly scheduled public meeting," would be removed from subparagraph (d)(1)(C).
- Subparagraph (d)(1)(D) would be added that states that notwithstanding the provisions of subparagraph (d)(1)(B), the operator of any stationary engine fired by landfill or digester gas (biogas) shall not operate the engine in a manner that exceeds the emission concentration limits in Table III.
- Provision (d)(1)(E) would be added that states that biogas engines operators that have established that they have complied with emissions limits of Table III-Bby January 1, 2015 would have their respective engine permit application fees refunded.
- The provision in Subparagraph (d)(1)(C) that states that there shall be no limit on the percentage of natural gas burned, once a engine complies with concentration limits effective on and after July 1, 2012, would be deleted and replaced with provision (d)(1)(F), which states once an engine complies with the concentration limits in Table III-B of the proposed amended rule, there would be no limit on the percentage of natural gas burned.
- The effective date of the rule provision that would exclude engines that operate less than 500 hours per year or use less than 1,000,000,000 Btus per year (higher heating value) of fuel on or after July 1, 2012, would be deleted from (d)(1)(C) and replaced with a new subparagraph (d)(1)(G) that states that the concentration limits in the Table III-B shall not apply to engines that operate less than 500 hours per year or use less than 1,000,000,000 Btus per year (higher heating value) of fuel.

- An operator of a biogas engine would be allowed to determine compliance with the NOx and/or CO limits of Table III-B by utilizing a longer averaging time as set forth in the proposed rule, provided that the operator demonstrates through CEMS data that the engine is achieving a concentration at or below 9.9 ppmv for NOx and 225 ppmv for CO (each corrected to 15 percent oxygen) over a four month time period. The operator would be allowed to use a monthly averaging time for the first four months of engine operation and up to a 12 hour averaging time thereafter. Additional requirements pertaining to CEMS monitoring related to this provision are included.
- Internal section references were updated to account for changes to section numbering caused by the proposed amendments.

Subdivision (e) - Compliance
No change.

Subdivision (f) – Monitoring, Testing, Recordkeeping and Reporting
A clarification would be made to (f)(1)(D)(iii)(I) that states that a return to a more frequent emission check schedule would not be required when making adjustments to the oxygen sensor set points if the engine is in compliance with the applicable emission limits prior to and after the set points adjustments, notwithstanding the requirements of (f)(1)(D)(iii)(IV).

Subdivision (g) – Test Methods
No change.

Subdivision (h) – Alternative Compliance Option

- In lieu of complying with the applicable emissions limits by the effective dates specified in Table III-B, owners/operators of affected biogas-fired units that operate under long term fixed price power purchase agreements that have been entered into prior to February 1, 2008 and extend beyond January 1, 2016 may elect to defer compliance by up to two years and no later than January 1, 2018, provided the owners/operators submit an alternative compliance plan and pay a compliance flexibility fee to the Executive Officer at least 150 days prior to the applicable compliance date in Table III-B, and maintains an on-site copy of verification of the compliance flexibility fee payment and SCAQMD approval of the alternative compliance plan available upon request to SCAQMD staff.
- The alternative compliance plan would be required to include a completed SCAQMD Form 400A; attached documentation of unit permit ID, unit rated brake horsepower, and fee calculation; filing fee payment; and compliance flexibility fee payment. The SCAQMD Form 400 A would need to identify that the request is for a compliance plan and identification that the request is for the Rule 1110.2 Compliance Flexibility Fee option.
- The compliance flexibility fees associated with the alternative compliance plan would be applied to SCAQMD NOx reduction programs pursuant to protocols approved under SCAQMD rules.

Subdivision (i) - Exemptions
Exemption (i)(10) would be clarified to include engine shutdown periods, as well as, engine start up periods.

CONTROL TECHNOLOGIES

Pre-combustion Biogas Cleanup Technologies

Biogas, whether coming from a wastewater treatment plant digester or from a landfill, has many impurities, including but not limited to sulfur-containing compounds and siloxane, that require treatment (filtered, dewatered, and compressed) before combustion. If left untreated, raw biogas can damage engine components that may result in more maintenance and ultimately, over time, reduce the useful life of the engine. For example, siloxane can crystallize as silicon dioxide in the combustion stage and become deposited in fuel lines and engine parts. As a result, more frequent major maintenance on engines may be required to clean deposits from untreated biogas within the engine. Failure to perform this maintenance may result in catastrophic failure of an engine. The pretreatment of biogas is even more critical for catalyst-based after-treatment technologies for engines. If left untreated, impurities such as siloxane may result in the rapid poisoning of the catalyst downstream of the engine. Poisoning of catalysts is defined as the deposition of silica on the active sites of the catalyst which reduces the efficiency of the catalyst.

As described in the Interim Technology Assessment, there are two types of siloxane removal systems, regenerative and non-regenerative. Regenerative siloxane removal systems do not require constant removal of the sorbent material from its vessel. It is regenerated using a heated purge gas. Typically there are two vessels, so one can be regenerated, while the second vessel continues to clean siloxane. The Ox Mountain Landfill has the only regenerative siloxane removal system in use for the protection of a post-combustion catalyst. Ox Mountain Landfill is located at Half Moon Bay, California, which is within the Bay Area Air Quality Management District's (BAAQMD) jurisdiction. The landfill gas to energy site (operated by Ameresco) has six GE-Jenbacher engines, each rated at 2,677 brake horsepower that are fired on landfill gas. All six engines have been retrofitted with oxidation catalysts, while one of the engines also has an SCR system. A temperature swing adsorption (TSA) regenerative siloxane removal system manufactured by GE-Jenbacher is used. Two adsorption beds of regenerative activated carbon are alternatively regenerated by using heat. The gas cleanup and oxidation catalyst/SCR systems were commissioned in 2009 and have shown to be very effective in the removal of siloxane from the landfill gas. Performance data shows that the system is removing between 95 and 99 percent of inlet siloxane.

Non-regenerative siloxane removal systems require periodic replacement of the adsorbent material (activated carbon or silica gel) once it is spent. Two beds of adsorbent are used, so one can be recharged with fresh adsorbent while the other removes siloxane. These systems are sized to handle site-specific siloxane loads. Greater amounts of adsorbent are required for biogas streams with higher levels of siloxane. The amount of adsorbent must be able to handle intermittent spikes in the biogas stream.

Control Technology for Internal Combustion Engines Analyzed in the 2007 Final EA

Potential impacts from using the following types of internal combustion engine control technologies were comprehensively analyzed in the 2007 Final EA previously certified by the SCAQMD Governing Board. As a result, even though operators of biogas-fueled engines affected by PAR 1110.2 may ultimately install these types of control technologies to comply with the emission reduction requirements, no further analysis of potential secondary impacts that may be generated by these control technologies is required. The following information is included for completeness only.

Catalytic Oxidation/Selective Catalytic Reduction

Proven and effective technologies for CO, VOC, and NOx control among natural gas fueled lean-burn engines include catalytic oxidation with selective catalytic reduction. If the raw biogas is cleaned sufficiently and effectively, there is little danger of fouling any post combustion catalyst by siloxane deposition.

Catalytic oxidation removes CO and VOC by chemical reactions facilitated by the catalyst. Oxidation catalysts contain precious metals that assist CO and VOC to react with oxygen to produce CO_2 and water vapor. Catalytic oxidation can reduce CO and VOC emissions by greater than 90 percent.

SCR can be used with lean-burn engines since the higher oxygen concentrations in the exhaust preclude the use of less costly nonselective catalytic reduction (NSCR). SCR requires the injection of a reducing agent, typically urea or ammonia, to react with the NOx in the engine's flue gas, producing water vapor and nitrogen gas as the end products. The SCR catalyst promotes the reaction of urea or ammonia with NOx and oxygen, and is a very effective NOx control technology.

NOxTech

NOxTech is another post combustion control technology, which does not require a catalyst, does not require gas cleanup, and is capable of achieving multi-pollutant control of NOx, VOC, and CO emissions. Engine exhaust gases enter the unit where the temperature is raised by a heat exchanger. The gases then enter a reaction chamber where a small amount of the engine's fuel is added to raise the gas temperature to between 1400 and 1500 degrees Fahrenheit. At this temperature the NOx reduction in the reaction chamber can occur using urea injection, while CO and VOC emissions are simultaneously incinerated. The system is designed to handle biogas that is of a lower Btu content than higher Btu content natural gas.

Biogas-fueled Engines – Replacement Technologies

The cost of compliance (CEMS, I&M, add-on control technology, etc.) may make it less costly to remove the existing biogas-fueled ICEs and replace them with other technologies. These technologies include boilers, gas turbines, microturbines, fuel cells and biogas-to-LNG systems. Replacing ICEs with the technologies described below means they would no longer be subject to the requirements of PAR 1110.2, but may be subject to other source-specific rules or regulations such as Regulation XIII – New Source Review.

Potential impacts from replacing biogas-fueled engines with the following replacement technologies were comprehensively analyzed in the 2007 Final EA previously certified by the SCAQMD Governing Board. As a result, even though operators of biogas-fueled engines affected by PAR 1110.2 may ultimately install these types of replacement technologies to comply with the emission reduction requirements, no further analysis of potential secondary impacts that may be generated by these control technologies is required. The following information is included for completeness only.

Fuel Cells

Fuel cells are an emerging technology capable of producing power with very low pollutant emissions without the utilization of combustion. Fuel cells can produce electricity much more efficiently than combustion-based engines and turbines. A fuel cell uses a molten carbonate cell or other media to create an electrochemical reaction with the inlet biogas at the anode and oxygen from air at the cathode. Hydrogen is created in a reforming process at the anode, while carbonate ions are created at the cathode. The hydrogen gas reacts with the carbonate ions to produce water and electrons. These electrons flow through an external circuit that produces the electricity for the power plant.

The electrochemical reactions are produced in individual molten carbonate electrolyte stacks. The stacks are modular in design, so the total power production capacity of the generating plant can be tailored to accommodate several fuel cell stacks to meet the desired power output. The heat generated by the fuel cells can also be recovered and used to provide process heat. For instance, the recovered heat can be used to supply heat to a wastewater treatment plant's anaerobic digesters. The fuel cell stacks, however, are sensitive to impurities, so a biogas cleanup system is critical to maintain the performance of the fuel cell stacks. Siloxane can foul a fuel cell.

There are many fuel cell installations that run on natural gas, and there are also several in California that operate on biogas.

Flex Energy

Flex Energy is a system that combines microturbine technology with that of regenerative thermal oxidation to produce power with an ultra low emissions profile and without the necessity of biogas cleanup. The system is capable of taking low Btu content biogas that would be otherwise incombustible by any engine or turbine and diluting it before introducing it to the thermal oxidizer that raises the temperature to destroy VOC and CO. The thermal oxidizer's temperature is also not raised high enough to facilitate the formation of thermal NOx. This process results in the consumption of methane gas without the pollutants from traditional combustion.

A typical internal combustion engine that runs on landfill gas will not operate efficiently if the methane content of the biogas drops below 35 to 40 percent. Landfills that produce gas with a methane content lower than what an engine typically needs to operate, will typically combust the gas with a flare. An advantage of the Flex Energy system is that it is capable of handling biogas with a methane content equivalent to and below a typical engine's range of consumption. An open landfill will often produce biogas with a constant amount of methane, roughly 50 percent. The other 50 percent of landfill biogas is typically CO_2. However, once a landfill ceases to accept municipal solid waste, the amount of biogas produced by the landfill will gradually begin to decay and the methane content will decline. A Flex Energy system can consume landfill gas well after a landfill closes at a lower methane content compared to other types of engines.

Another advantage with this type of system is that it does not require a fuel cleanup system for siloxane and other impurities. Like the fuel cells, these systems can be modularly applied, based on the inlet characteristics of the biogas and desired power output.

Other Combustion Technologies Analyzed in the 2007 Final EA

Potential impacts from replacing biogas-fueled engines with the following types of combustion technologies were comprehensively analyzed in the 2007 Final EA previously certified by the SCAQMD Governing Board. As a result, even though operators of biogas-fueled engines affected by PAR 1110.2 may ultimately install these other types of technologies to comply with the emission reduction requirements, no further analysis of potential secondary impacts that may be generated by these control technologies is required. The following information is included for completeness only.

Traditional gas turbines, microturbines and boilers fall under this category and typically have lower emission profiles overall than biogas-fueled engines. Several landfills in the Basin currently employ the use of gas turbines for combustion of the biogas and also require extensive gas cleanup to protect the turbine blades from siloxane buildup. For example, the Calabasas Landfill operated by Los Angeles County Sanitation District and the Brea-Olinda Landfill currently use gas turbine technology with gas cleanup for handling landfill produced biogas. Traditional boilers can also process biogas and currently are being used by both landfills and wastewater treatment plants across the basin. For example, if a facility that operates both engines and boilers chooses to shut down its engines, the remaining biogas can usually be handled by its boilers and any excess can be routed to the existing facility flare, if necessary. Boilers are less sensitive to impurities and do not require extensive gas cleanup.

Liquefied Natural Gas (LNG) Facilities

Potential impacts from replacing biogas-fueled engines with LNG facilities were comprehensively analyzed in the 2007 Final EA previously certified by the SCAQMD Governing Board. As a result, even though operators of biogas-fueled engines affected by PAR 1110.2 may ultimately install these types of control technologies to comply with the emission reduction requirements, no further analysis of potential secondary impacts that may be generated by these control technologies is required. The following information is included for completeness only.

Biogas-to-LNG systems convert biogas to LNG and CO2. LNG is created when natural gas is cooled to minus 260 degrees Fahrenheit, reducing six-hundred cubic feet of gas into one cubic foot of liquid methane. This process consists of several stages of compression and cooling. LNG plants would consist of a power generation building, programmable logic control/motor control center building, compression skids, refrigeration skids, liquefier skids, storage tanks and loading equipment. The plant is typically composed of vessels, compressors, pipes, valves, filters, coolers, instruments and process components in six modules: purification, CO2 removal, refrigeration, liquefaction and post purification, instrument air, and controls. An LNG storage and dispensing system is needed to transfer LNG from the facility to trucks.

The LNG facility at the Frank R. Bowerman Landfill in Irvine, California was used as a basis for the analysis in the 2007 Final EA.[2] The Bowerman facility uses biogas-fueled turbines to supply power to the LNG facility. Since LNG systems are assumed to replace existing ICEs at affected facilities, it was assumed that facility operators who choose to install LNG plants in place of existing ICEs would use electricity from the power grid. Since the LNG facility would require some energy in the form of heat, it was assumed that operators who replace existing ICEs at affected facilities would install boilers to generate heat for the facility.

---

2 Prometheus Energy Company, Bowerman I Natural Gas Process Facility Project Description, prepared for SCAQMD, undated.

The Bowerman facility has a LNG storage tank that can store five days worth of LNG generated at the facility. Dr. John Barclay of Prometheus Energy has stated that typical design of LNG storage tanks includes a capacity of three days.[3]

Flares

All facilities in the district that would be subject to PAR 1110.2 currently use flares onsite, either as one means of controlling landfill gas or as a backup to other types of biogas control or combustion technologies for use in event of emergency shutdowns or shutdowns for maintenance. Replacing existing biogas-fueled engines with flares, which means the equipment would no longer be subject to Rule 1110.2, was considered for analysis in the 2007 Final EA, but was rejected because, at the time, it was considered to be unlikely that operators of biogas-fueled engines would remove the biogas-fueled engines in favor of using flares. Recent information indicates that there is a potential to replace biogas-fueled engines with flares. Consequently, the analysis of potential adverse environmental impacts from switching from biogas-fueled engines to flares as a result of adopting PAR 1110.2 is the main focus of this Addendum. Therefore, the following paragraph provides a brief description of a landfill gas flare.

The major components of a flare are gas burner, stack, liquid trap, controls, pilot burner, and ignition system. Some flares are equipped with automatic pilot ignition systems, temperature sensors, and air and combustion controls. Flare combustion efficiency is related to flame temperature, residence time of gases in the combustion zone, turbulent mixing of the combustion zone, and amount of oxygen available for combustion. The temperature of exhaust gases from flares can range from 1,000 to 2,000 degrees Fahrenheit.

Flares are often the last resort for any facility that handles biogas, but cannot combust it with other means because of an insufficient quantity or methane content. With flaring, a facility can achieve VOC destruction from combustion, while many newer BACT flares achieve low NOx emissions. Although flares are used to combust methane to produce CO2, which has a lower global warming potential, PAR 1110.2 has the potential to create CO_2 emission impacts, which will be discussed elsewhere in this document.

DISCUSSION AND EVALUATION OF ENVIRONMENTAL IMPACTS

Implementation of the biogas-fueled engine NOx concentration limits adopted in 2008 were conditional on preparation of a technology assessment verifying that the NOx concentration limits could be achieved by affected engines. Further, the technology assessment was required to be presented to the Governing Board at the July 2010 Public Hearing. Because the technology assessment was not completed in time for the July 2010 Public Hearing, the biogas-fueled engine NOx concentration limits did not become effective; therefore, the NOx concentration limits from the previous version of Rule 1110.2 remained in effect. As a result, NOx emission reductions associated with biogas-fueled engines cannot be claimed for the 2008 amendments to Rule 1110.2. Consequently, adopting NOx concentration limits for biogas-fueled engines with later compliance dates than those in the 2008 amendments to Rule 1110.2 means that previously quantified emission reductions for biogas-fueled engines are not considered to be foregone or delayed.

[3] Phone conversation between Dr. John Barclay, Chief Technology Officer of Prometheus Energy Company and James Koizumi of SCAQMD, August 1, 2007.

The December 2007 Final EA assumed that operators of biogas-fueled ICEs would retrofit their engines with SCRs and catalytic oxidization systems or NOxTech systems. However, the December 2007 Final EA also evaluated the environmental impacts from the replacement of biogas-fueled ICEs with gas turbines, microturbines, or LNG plants. Options where landfill gas systems were replaced with LNG plants and digester gas systems with either turbines or microturbines were also evaluated. If, as part of the proposed amendments, operators choose to replace biogas-fueled ICEs with any of the above identified technologies, potential adverse environmental impacts from the technologies evaluated in the December 2007 Final EA would be the unchanged, although they would occur later because of the proposal to set the final compliance date as January 1, 2016 or January 1, 2018 under the alternative compliance option. Therefore, because impacts from the above technologies were already analyzed in the 2007 Final EA and are not expected to change as a result of adopting the currently proposed amendments to Rule 1110.2, they will not be considered further in this Addendum.

Flares are currently used as a means to control landfill gas at a number of affected facilities in the district. Flares are also located at facilities with biogas-fueled ICEs to combust the biogas in the event the biogas-fueled ICEs are not operating due to maintenance or breakdowns. Replacing existing biogas-fueled engines with flaring, means the biogas equipment would no longer be subject to Rule 1110.2, since Rule 1110.2 applies only to ICEs. Replacing biogas-fueled ICEs with flares was not analyzed in the 2007 Final EA because it was assumed biogas-fueled ICEs would be able to comply with the final emission concentration limits by using the new provision that allows biogas facilities to use more than 10 percent natural gas in biogas-fueled engines. Further, the technology assessment was expected to provide regulatory relief in the event that the results demonstrated that biogas-fueled ICEs could not comply with the final compliance limits.

More recently, feedback from Rule 1110.2 stakeholder working group indicated that, because of the potential difficulty that biogas-fueled engines may have in complying with the final NOx concentration requirements, operators may consider replacing affected engines with flaring biogas with existing flares, as flaring biogas is not prohibited under any existing SCAQMD regulations. The reason for this assertion is that some biogas-fueled engines are reaching the end of their useful lives and it would not make economic sense to retrofit engines that will need to be replaced within a relatively short period of time. Further, the quality of biogas (methane content) at some landfill gas facilities is declining, so it will be more difficult to combust this biogas in biogas-fueled ICEs. So, rather than retrofit existing biogas-fueled ICEs to comply with Rule 1110.2 during the period of declining biogas quality, it may be more economical to replace them with flaring. Therefore, the following analysis of potential adverse environmental impacts from adopting PAR 1110.2 focuses primarily on potential secondary adverse environmental impacts from replacing biogas-fueled engines with flaring and whether or not impacts are within the scope of the environmental analysis in the 2007 Final EA. However, all environmental topic areas from the environmental checklist (CEQA Guidelines, Appendix G) were evaluated to ensure that no potential impacts from adopting PAR 1110.2 are overlooked.

PAR 1110.2 includes an alternative compliance option for private owners/operators of biogas-fired engines with emission concentration limits in Table III-B. Under the alternative compliance option, private owners/operators of affected biogas-fired engines could elect to defer compliance with the emission limits in Table III-B by up two years. PAR 1110.2 states that the funds collected from the compliance flexibility fee would be applied to NOx reduction programs pursuant to protocols approved under SCAQMD rules. Since all SCAQMD rules undergo

CEQA review prior to adoption any environmental impacts from NOx reduction programs pursuant to protocols approved under SCAQMD rules have been evaluated, disclosed and mitigated if necessary. It goes without saying that any expenditure of Rule 1110.2 funds would be consistent with the CEQA analyses for the protocols approved under SCAQMD rules, so that no expenditure would be allowed if it would cause any exceedance of what was analyzed in the associated CEQA documents.

The NOx reduction programs funded by the compliance flexibility fees under PAR 1110.2 are likely to be similar to the GHG reduction protocols under Rule 2702 – Greenhouse Gas Reduction Programs associated with combustion processes, since these GHG reduction protocols also reduce NOx emissions. GHG reduction protocols from Rule 2702 that would also reduce NOx emissions include:

- Boiler efficiency protocols – this protocol includes the installation of economizers or oxygen trim systems. Economizers are heat exchangers installed in flue gas ductwork between the boiler outlet and stack, which cools the flue gas. Oxygen trim systems add more precise air control based on a fuel flow sensor, electronic controller and servo-based damper positioner to reduce the amount of excess air.
- Lawn mower protocol – this protocol offers cordless electric lawn mowers to consumers at a subsidized price in exchange for old operable gasoline powered lawn mowers.
- Leaf blower protocol – this protocol offers four-stroke engine leaf blowers to professional gardeners/landscapers at a subsidized price in exchange for old operable two-stroke engine leaf blowers.
- Truck stop electrification protocol – this protocol provides funds to install external sources of heating, ventilation and air conditioning at truck stop locations. The units are attached into the side window of truck cabs at locations where trucks stop in lieu of using the truck auxiliary engines for cooling and heating. The units are powered by fixed electrification structure or trusses over truck parking spaces.

Impacts from these protocols were analyzed in the Final Program EA for Proposed Rule 2702 – Greenhouse Gas Reduction Programs (SCAQMD No. 081104MK, State Clearinghouse No., 2008111002) dated December 31, 2008, and determined not to be significant for any environmental topic. At that time the analysis assumed up to $2.8 million per year might be spent on any one of these protocols, yet the impacts would not be significant. SCAQMD staff estimates that no more than 2.5 million per year ($5,394,848 total over two years) would be obtained in compliance flexibility fees under Rule 1110.2. If significantly more money was obtained expenditures could be limited so that the 2.8 million per year analyzed would not be exceeded. Therefore impacts using these protocols under PAR 1110.2 would also not be significant. Since PAR 1110.2 would not result in emissions foregone or delayed, there is no need for any compliance flexibility fees submitted to the SCAQMD to achieve a particular amount of NOx emission reductions to avoid potentially significant air quality impacts from NOx emissions foregone or delayed. Therefore, any NOx emission reductions and any other associated emission reduction co-benefits that would occur through applying the compliance flexibility fees to protocol programs identified in PAR 1110.2 would be solely for the benefit of environment. Therefore, together with other anticipated uses of Rule 2702 protocols, NOx reduction programs funded by PAR 1110.2 compliance flexibility fees are expected not exceed the usage assumed in the 2008 Program EA for Rule 2702.

Aesthetics

PAR 1110.2 would include the same NOx concentration limits for biogas-fueled ICEs that would have become effective July 1, 2012, if the technology review had been completed in 2010. The current proposal would extend the effective final NOx compliance dates to either January 1, 2016, or January 1, 2018, depending on whether the owners/operators elect and qualify for the the alternative compliance option. The analysis of the currently proposed amendments concluded that aesthetics impacts would be no greater than the significant adverse aesthetic impacts identified in the 2007 Final EA. The conditions that contributed to significant adverse aesthetics impacts in Final 2007 EA would not occur with replacing existing biogas-fueled ICEs with flares for the following reasons.

Flaring biogas in lieu of complying with the 2008 amendments to Rule 1110.2 was not expected to occur and; therefore, was not fully evaluated in the 2007 Final EA. All existing biogas facilities have flares that are used to burn biogas when biogas-fueled engines are not operating. Although, initially it was assumed in the 2007 Final EA that adding new flares may further degrade the existing visual character of the facility, it was concluded that this impact would not occur because information industry representatives indicated that removing biogas-fueled ICEs and flaring biogas instead, would occur in existing flares at existing affected facilities (i.e., no new flares are expected to be built). Because the existing biogas-fueled flares have covers, no open flames are visible outside of the flares.

In addition to flares, affected digester gas facilities have emergency standby generators that can be used to support the plant during emergencies. In the event that biogas-fueled ICEs are replaced by flares, emergency standby generators would continue to operate only during emergencies. Therefore, no new emergency standby generators are expected to be necessary. However, if new emergency standby generators are installed, they are expected to be dropped into place and to look similar to the existing biogas-fueled ICEs and/or existing emergency standby generators. For these reasons, the April 20, 2007 NOP/IS for the 2007 Final EA concluded that no new aesthetics or light and glare impacts would occur. This conclusion would continue to be the case for PAR 1110.2. This situation is different compared to the circumstances that contributed to significant adverse aesthetics impacts identified in the 2007 Final EA as summarized below.

The 2007 Final EA included and evaluation of replacing existing biogas-fueled ICEs with biogas-to-LNG facilities, gas turbines, microturbines or boilers. Although turbines, microturbines and boilers are similar in physical characteristics to ICE systems, because of space issues, and location of utilities, location and quality of biogas sources, and piping; aesthetic impacts may be significant if new equipment is located near the property boundary or, in the case of biogas-to-LNG facilities, large process equipment and truck loading racks may be visible from outside of the facility. Further, if the process equipment operates at night there may be a need additional lighting. Therefore, the 2007 Final EA determined that installation of a biogas-to-LNG facility may significantly alter the aesthetics of an existing facility.

To the extent that affected facility operators replace biogas-fueled ICEs with turbines, microturbines, and boilers, potentially significant adverse impacts would be delayed three and a half to six years depending on whether the owners/operators elect and qualify for the alternative compliance option. However, this impact was previously analyzed in the 2007 Final EA. Replacing biogas-fueled ICEs with flares, is potentially the case under PAR 1110.2, would not create new significant adverse effects on scenic vistas; would not add new substantial damage scenic resources, including, but not limited to, trees, rock outcroppings, and historic buildings within a state scenic highway; would not add new substantial degradation to the existing visual character or quality of the site and its surroundings; or create a new source of substantial light or glare which would adversely affect day or nighttime views in the area.

Based upon the above considerations, the proposed project would not create new aesthetics impacts or make substantially greater significant adverse aesthetics impacts identified in the 2007 Final EA. Since no new significant or substantially worse adverse aesthetics impacts were identified, no mitigation measures are necessary or required.

Agriculture and Forest Resources

PAR 1110.2 would include the same biogas NOx concentration limits previously proposed for July 1, 2012 with effective dates that extend out to January 1, 2016 or January 1, 2018 under the alternative compliance option. Analysis of the 2008 amendments to Rule 1110.2 in the April 20, 2007 NOP/IS concluded that the 2008 project would not generate any agricultural resources impacts. Any replacement or retrofit construction would occur at existing commercial or industrial facilities. No comments were received on the NOP/IS that refuted this conclusion, so this topic was not analyzed further in the 2007 Final EA.

Potential impacts to forestry resources were not evaluated in the 2007 Final EA because this topic was not added to the environmental checklist until the year 2010, which was after the 2007 Final EA was certified. Biogas-fueled engines are located at existing facilities, and any construction or operation is expected to occur on-site. Therefore, PAR 1110.2 is not expected to have forestry impacts. With regard to the currently proposed project, no impacts to agricultural or forestry resources are anticipated as explained below.

Flaring biogas in lieu of complying with the 2008 amendments to Rule 1110.2 was not expected to occur and; therefore, was not fully evaluated in the 2007 Final EA. However, since any biogas flaring in lieu of complying with PAR 1110.2 would occur using existing biogas-fueled flares, flaring would also occur on-site at existing facilities. PAR 1110.2 may result in the early removal of the biogas-fueled ICEs, but the similar impacts were evaluated under other equipment replacement scenarios and it was concluded in the 2007 Final EA that no impacts to agriculture would occur. This conclusion would continue to apply to the currently proposed project, even in the event that biogas-fueled ICEs are removed at a later date. The removal of the biogas-fueled engines is not expected to affect agricultural or forestry resources since the engines are placed on concrete pads on-site.

Digester gas facilities have emergency standby generators that can be used to support the plant during emergencies. Although no new emergency standby generators are expected to be needed, if existing emergency standby generators are replaced with new emergency standby generators, they are expected to be dropped in place within the boundaries of existing biogas facilities.

Therefore, based on the above information, PAR 1110.2 would not convert farmland to non-agricultural use; or conflict with existing zoning for agricultural use, or a Williamson Act contract. Therefore, it is not expected that PAR 1110.2 would conflict with existing zoning for, or cause rezoning of, forest land; or result in the loss of forest land or conversion of forest land to non-forest use. Consequently, the proposed project would not create new significant adverse agriculture or forestry impacts or make substantially greater significant adverse impacts identified in the 2007 Final EA. Since no significant or substantially worse adverse agriculture or forestry resources impacts were identified, no mitigation measures are necessary or required.

Air Quality and Greenhouse Gas Emissions

Conflict with an Applicable Air Quality Plan

The 2007 NOP/IS concluded that the 2008 amendments to Rule 1110.2 would contribute directly to carrying out the goals of the 2007 AQMP by implementing, in part, control measure MSC-01 – Facility Modernization. Because it is expected to reduce NOx, VOC and CO emissions from all affected source categories, which in turn, would contribute to attaining the state and federal ambient air quality standards. Thus, adopting the 2008 amendments to Rule 1110.2 was not expected to conflict or obstruct implementation of the applicable AQMP. PAR 1110.2 would not obstruct or conflict with the implementation of the AQMP because, overall, Rule 1110.2 achieves net emission reductions. The emission reductions from stationary engines fired by biogas were not included in the SIP submittal and so did not contribute to the SCAQMD's efforts to attain national ambient air quality standards. However, emission reductions resulting from PAR 11110.2 are expected to contribute to the SCAQMD's ambient air quality standards attainment efforts.

Criteria Pollutants

<u>Summary of the Criteria Pollutant Analysis in the 2007 Final EA</u>

To provide a worst-case analysis, the 2007 Final EA assumed that construction to install control equipment on biogas-fueled ICEs or replace existing biogas-fueled ICEs with other biogas control technologies and operation of controlled or replaced equipment would overlap in the year 2012. For non-biogas-fueled ICEs construction to install control equipment and operation of affected engines were expected to occur and overlap in the years 2008 through 2011. Therefore, potential emission impacts from PAR 1110.2 were compared to the worst-case emissions estimated for 2012 in the 2007 Final EA, the year biogas-fueled ICEs would be retrofitted with control technologies or replaced by other technologies not subject to PAR 1110.2.

The 2007 Final EA included an analysis of overlapping construction and operational criteria pollutant emissions from four worst-case scenarios: 1) the addition of after treatment on biogas-fueled ICEs, 2) the replacement of biogas-fueled ICEs with gas turbines, 3) the replacement of biogas-fueled ICEs with microturbines, 3) the replacement of biogas-fueled ICEs with gas turbines at digester gas facilities and LNG facilities at landfill gas facilities, and the replacement of biogas-fueled ICEs with microturbines at digester gas facilities. Because of space issues, it was deemed impractical for biogas-fueled facility operators to install LNG equipment at landfill gas facilities. Since impacts from the above technologies have already been analyzed, the analysis of PAR 1110.2 will focus on air quality impacts associated with replacing biogas-fueled ICEs with existing flares.

Construction Impacts

All facilities that operate biogas-fueled ICEs also have existing flares that are operated when the biogas-fueled ICEs are not operating either in emergency situations or when biogas-fueled ICEs are offline for maintenance. Since biogas facilities have existing flares that can be used to flare all biogas from the facilities during emergencies or maintenance, replacing existing biogas-fueled ICEs with flares would not require new flares to be installed because of PAR 1110.2.

Facility operators may remove existing ICEs before the end of their useful operating life to avoid costs associated with replacing engines that would only operate a few years until the existing replacement flares begin operating full time. If operators choose to replace biogas-fueled engines with flares before the end of their useful life, potential demolition air quality impacts, would likely occur earlier, but no new adverse demolition air quality impacts are expected, they would simply occur sooner. In addition, demolition of existing biogas-fueled engines would be no greater than the worst-case construction air quality impacts evaluated in the 2007 Final EA, which was removing an entire existing biogas-fueled engine system and installing a LNG plant.

The 2007 Final EA assumed that emergency backup engines would be installed at digester gas facilities that replaced existing biogas-fueled engines with alternative technologies that do not generate electricity. Subsequent to the adoption of the 2008 amendments, it was determined that all digester facilities already have existing diesel emergency engines for the same reasons they have flares, i.e., when the biogas-fueled ICEs are not operating either in emergency situations or when biogas-fueled ICEs are offline for maintenance. To be conservative, the 2007 Final EA evaluated construction emissions from replacing existing diesel emergency standby engines with new diesel emergency standby engines are included in the analysis of overlapping construction and operation air quality impacts. Construction emissions only from replacing existing diesel emergency standby engines with new diesel emergency standby engines are presented in Table 2.

Table 2
Secondary Construction Criteria Pollutant Emissions Potentially Associated with Flaring Operations in Lieu of Complying with PAR 1110.2

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5, lb/day
Construction Emissions from Installing Emergency Standby Engines[a]	53	22	6.4	0.02	2.7	2.7

a) Source: Table 4-34 – Criteria Construction Emissions for Biogas and Non-biogas Facilities from Installing SCR, Gas Turbines or Microturbines at All Biogas Facilities of the 2007 Final EA, year 2012. It was assumed that construction emissions from installing control equipment were equivalent to installing a new emergency standby engine.

Operational Impacts

Direct Air Quality Impacts from Flaring

Flaring biogas in lieu of complying with PAR 1110.2 was not evaluated in the 2007 Final EA. Any flaring of biogas in lieu of complying with PAR 1110.2 would occur in existing flares and would displace combustion in biogas-fueled ICEs. Flaring biogas would generate criteria pollutant emissions from the combustion of the biogas in the flares rather than in the biogas-fueled ICEs. Direct criteria pollutant emissions from daily flaring are presented in Table 3. The direct flare emissions shown in Table 3 were derived using the same biogas emissions usage rates that were used to quantify direct emission from biogas-fueled ICEs complying with the concentration limits in the 2008 amendments to Rule 1110.2 and analyzed in the 2007 Final EA. NOx, CO and VOC emissions were estimated using emission factors developed from source test results. SOx emissions from flares would be the same as those from ICEs because SOx is generated by the sulfur content of the fuel, which would be the same regardless of combustion equipment. Based on source tests, the PM emissions from flares would be the similar to those from ICEs.

Table 3
Criteria Pollutant Emissions Generated by Flaring Operations in Lieu of Complying with PAR 1110.2

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5, lb/day
Direct Emissions from Flaring Biogas[a]	683	1,402	427	464	136	136
Emissions from Additional Electricity Generation[b]		431	35		45	45
Secondary Emergency Standby Engines[c]	42	114	12	0.42	3.6	3.6
Total Emissions from Flaring Operations	725	1,947	474	464	185	185

a) Direct emissions from flaring biogas are total daily flare emissions and do not take into consideration baseline combustion emissions.
b) Source: Table 4-15 of the 2007 Final EA for PAR 1110.2.
c) Source: Table 4-19 of the 2007 Final EA for PAR 1110.2

Secondary Air Quality Impacts from Flaring
Biogas-fueled ICEs are typically used to generate electricity for onsite equipment and may sell any excess electricity to the electricity grid. In addition to backup flares all facilities that operate biogas-fueled ICEs also operate emergency backup generators to produce electricity in the event that the biogas-fueled ICEs are not operating due to emergencies or maintenance. In such situations, the emergency backup generators would need to operate to continue supplying electricity to onsite equipment.

If all of the biogas is flared instead of being combusted in the biogas-fueled ICEs, then the facility would need electricity from the grid to power operations currently powered by the existing biogas-fueled ICEs. The electricity needed at a facility that replaces biogas-fueled ICEs with flares would only need to be equivalent to the amount formerly generated by the existing ICEs. However, as demonstrated in the 2007 Final EA, replacing biogas-fueled ICEs with LNG plants would require additional energy from the grid, not only to operate existing onsite equipment, but to operate the new LNG plant. Table 3 presents the estimated criteria pollutant emissions from the 2007 Final EA for power plants generating electricity necessary to operate equipment at biogas facilities that replace biogas-fueled ICEs with flares.

In addition to quantifying emission for facilities that replace biogas ICEs with alternative technologies that do not generate electricity in lieu of complying with PAR 1110.2, the 2007 Final EA also analyzed emissions from emergency standby diesel engines. Although, SCAQMD staff has determined that digester gas facilities already have existing diesel emergency standby engines, to provide a conservative analysis it was assumed that facility operators who flare biogas in lieu of complying with PAR 1110.2 would also install new diesel emergency standby engines. Table 3 presents the criteria emissions from diesel fueled emergency standby engines from the 2007 Final EA for biogas facilities.

Total Criteria Emission Impacts from Flaring

2007 Final EA and Proposed Project Baselines

The emission estimates in the 2008 Final Staff Report and 2007 Final EA for the baseline and the project were based on a combination of rule limits, and source test values, which were lower than the emission limits in the existing and proposed project versions of Rule 1110.2. During the current rule making for this proposed project, emissions estimated in the Staff Report were based on the existing Rule 1110.2 and PAR 1110.2 emission limits. The baselines from the 2007 Final EA and the proposed project are presented in Table 4. Because the 2007 Final EA emission estimates for baseline include source test emissions (closer to actual emissions), they are lower than those estimated for the proposed project in the Staff Report for PAR 1110.2 (potential emissions), the baseline emissions estimate in the 2007 Final EA would result in fewer emission reductions (emission reductions are estimated by subtracting the project emissions from the baseline), which is conservative. Therefore, the 2007 Final EA emission baseline was used for this analysis.

Table 4
2007 Final EA and Baseline and Baseline Based on Existing Rule 1110.2 Emission Limits

Description	NOx, lb/day	CO, lb/day	VOC, lb/day
2007 Final EA (Source Test and Emission Limits)	1,859	9,555	882
Existing Rule 1110.2 Limits Only	2,600	51,200	1,600

Criteria Pollutants from Flaring Operations in Lieu of Complying with PAR 1110.2

The total criteria pollutant emissions from flaring operations (including secondary emissions) are presented in Table 5. The total criteria pollutant emissions include both construction and operational emissions, since it is possible that construction and operation could overlap.

Table 5
Evaluation of Criteria Emissions Generated by Flaring Operations in Lieu of Complying with PAR 1110.2

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5, lb/day
Biogas Baseline Emissions[a]	1,859	9,555	882	464	136	136
Flare Related Construction Emissions[b]	53	22	6.4	0.02	2.7	2.7
Flare Related Operational Emissions[c]	725	1,947	474	464	185	185
Difference in Emissions[d]	(1,081)	(7,586)	(402)	0.02	52	52
Significance Threshold	55	550	55	150	150	55
Significant?	No	No	No	No	No	No

a) Biogas-fueled engine baseline from Table 3. 2007 Final EA biogas-fueled engine baseline.
b) Flare – construction criteria emissions from Table from Table 2
c) Flare – operational criteria emissions from Table from Table 3.
d) Difference in emissions = biogas baseline emissions – (flare related construction emissions + flare related operational emissions.)

Numbers in parentheses represent emission reductions.

Emissions from flaring in lieu of complying with PAR 1110.2 are compared to existing emission from biogas-fueled ICEs in Table 5. The difference between criteria pollutant emission generated by flaring operations in lieu of complying with PAR 1110.2 and existing biogas-fueled ICEs were compared to the operational significance thresholds since construction and operations may overlap to be conservative (i.e., since operational significance thresholds are more stringent than construction significance thresholds). Flaring operations in lieu of complying with PAR 1110.2 would generate lower NOx, CO and VOC emissions that the existing biogas-fueled engines (i.e., NOx, CO and VOC emission reductions). SOx (0.02 pounds per day), PM10 (52 pounds per day) and PM2.5 (52 pound per day) emissions would be greater than those generated by existing biogas-fueled ICEs because of secondary emissions, but would not exceed the significant thresholds for SOx (150 pounds per day), PM10 (150 pounds per day) or PM2.5 (55 pounds per day).

Toxic Air Contaminants

The flaring of biogas in lieu of complying with PAR 1110.2 was not examined in the 2007 Final EA. The flaring of biogas currently occurs at biogas facilities when biogas-fueled ICEs are not operating because of emergencies or for maintenance. Biogas-fueled engines and flares are tested at the inlet and outlet for Rule 1150.1 Table 1 and Table 2 compounds. Based on a review of Rule 1150.1 flares typically have greater destruction efficiency than biogas-fueled ICEs. Therefore, biogas flaring in lieu of complying with PAR 1110.2 would result in potentially lower toxic air contaminant (TAC) emissions.

The 2007 Final EA estimated that the worst-case carcinogenic health risk would occur if biogas-fueled ICEs are replaced with alternative technologies in lieu of complying with PAR 1110.2. Although affected facility operators who replace biogas-fueled ICEs with alternative technologies may also need to install emergency standby diesel engines to power the facility when the alternative technology is not operating, the 2007 Final EA indicated that biogas facilities already have existing diesel emergency standby generators that are only operated periodically to ensure operability. Taking a conservative approach it was estimated that the diesel emergency standby generators would be installed at affected facilities and could potentially generate a carcinogenic health risk of 3.4 in one million, which is less than the SCAQMD's cancer risk significance threshold of 10 in one million. Because affected facilities already have emergency standby diesel engines, the 3.4 in one million is considered to be a conservative estimate.

In the 2007 Final EA the worst-case cancer risk impacts analyzed would occur if affected biogas facility operators that have both biogas-fueled and natural gas-fueled non-biogas-fueled ICEs onsite and replaced them with electric motors and emergency standby diesel engines. The worst-case carcinogenic heath risk replacing a natural gas-fueled non-biogas-fueled ICEs with electric motors and diesel emergency backup generators was calculated to be 18 in one million. This risk, when added to the risk of replacing an existing emergency standby diesel engine with a new engine, produced an estimated cancer risk of 21.4 in one million (3.4 in one million + 18 in one million). Therefore, the worst-case health risk of 21.4 in one million, which was determined to be significant in the 2007 Final EA, is substantially greater than the potential cancer risk of replacing existing biogas-fueled ICEs with flares.

Since PAR 1110.2 would not generate any new TAC emissions beyond what was already evaluated in the 2007 Final EA, PAR 1110.2 is expected to be less than significant for adverse TAC emission impacts and well within the scope of the cancer risk analysis in the 2007 Final EA.

Cumulatively Considerable Impacts

Since new adverse air quality impacts from implementing PAR 1110.2 are not expected to exceed any project-specific air quality significance thresholds, air quality impacts are not expected to be cumulatively considerable as defined in CEQA Guidelines §15064(h)(1).

Odor Impacts

The 2007 Final EA examined potential odor impacts from ammonia slip related to SCR units, diesel exhaust odor from additional diesel truck trips and from emergency standby diesel ICEs related to alternative technologies used in lieu of biogas-fueled ICEs. However, the odor impacts analysis in the 2007 Final EA concluded that there would be no significant adverse odor impacts.

The 2007 Final EA did not specifically evaluate potential odor impacts from replacing existing biogas-fueled ICEs with flares. Since the primary effect of adopting PAR 1110.2 is assumed to be replacement of biogas-fueled ICEs with flares, less than significant odor impacts from replacing biogas-fueled ICEs with other technologies or install control equipment evaluated in the 2007 Final EA would be unchanged. Further, replacing biogas-fueled ICEs with flares does not involve the use of ammonia and is not expected to affect operations or change the number of truck trips visiting affected facilities.

This analysis also assumed that those facility operators who replace biogas-fueled ICEs with flares would also install new emergency standby diesel engines as backups to provided electricity in the event of power outages. Emergency standby diesel engines are limited to 50 hours of operation per year for testing. Testing events typically don't last more than 30 minutes and usually no more frequently than once per week. Because of this limitation no odor impacts are expected.

For the above reasons PAR 1110.2 is not expected to generate significant adverse odor impacts or make an existing adverse impact substantially worse from replacing biogas-fueled ICEs with flares.

Greenhouse Gas Impacts

Global warming is the observed increase in average temperature of the earth's surface and atmosphere. The primary cause of global warming is an increase of greenhouse gas (GHG) emissions in the atmosphere. The six major types of GHG emissions are carbon dioxide (CO2), methane (CH4), nitrous oxide (N2O), sulfur hexafluoride (SF6), haloalkanes (HFCs), and perfluorocarbons (PFCs). The GHG emissions absorb longwave radiant energy emitted by the earth, which warms the atmosphere. The GHGs also emit longwave radiation both upward to space and back down toward the surface of the earth. The downward part of this longwave radiation emitted by the atmosphere is known as the "greenhouse effect."

The current scientific consensus is that the majority of the observed warming over the last 50 years can be attributable to increased concentration of GHG emissions in the atmosphere due to human activities. Events and activities, such as the industrial revolution and the increased consumption of fossil fuels (e.g., combustion of gasoline, diesel, coal, etc.), have heavily contributed to the increase in atmospheric levels of GHG emissions. As reported by the California Energy Commission (CEC), California contributes 1.4 percent of the global and 6.2 percent of the national GHG emissions (CEC, 2004). Further, approximately 80 percent of GHG emissions in California are from fossil fuel combustion (e.g., gasoline, diesel, coal, etc.).

The 2007 Final EA estimated GHG emissions from construction and operation assuming both full compliance with the 2008 amendments (i.e., without any electrification) and compliance with the 2008 amendments. The 2007 Final EA first evaluated cost estimates for replacing existing ICEs with electric motors in certain applications instead of incurring the costs of installing emissions controls and monitoring and inspection and maintenance (I&M) equipment that would be necessary to comply with PAR 1110.2. SCAQMD staff identified 225 nonbiogas engines where operators would incur lower compliance costs if they replaced them with electric motors and assumed that 75 percent of these engines (169) would voluntarily be replaced with electric motors. The analysis indicated that replacing all 169 nonbiogas engines with electric had the potential of reducing GHG emissions by 107,276 metric tons per year[4]. Further, the analysis also determined that if at least 15 ICEs were replaced with electric motors, there would be no additional GHG emissions generated by the 2008 amendments to Rule 1110.2. It was assumed that at least 15 of the 169 non-biogas-fueled ICEs would be replaced, so the 2008 amendments to Rule 1110.2 analyzed in the 2007 Final EA were assumed to be less than significant for GHG emissions. PAR 1110.2 is not expected to affect in any way replacement of nonbiogas engines with electric motors because the proposed amends only affect biogas-fueled ICEs.

Since GHG emissions are based on fuel usage, the GHG emissions from flaring biogas would be the same as combusting biogas in an ICE. Based on the analysis for the 2007 Final EA approximately 115.5 metric tons of CO2 per year would be generated by power plants to support a facility that no longer generated electricity from biogas. The analysis also estimated that emergency standby engines would generate 307 metric tons of CO2. Therefore, replacing existing biogas-fueled ICEs with flares would be expected to generate GHG emission of approximately 423 metric tons per CO2 would be generated, which is essentially the same as replacing existing biogas-fueled ICEs with other types of technologies and less than the SCAQMD significance threshold of 10,000 metric tons per year. Consequently, GHG emission impacts from PAR 1110.2 are within the scope of the analysis of GHG impacts in the 2007 Final EA.

Therefore, the proposed project would not substantially alter the conclusion in the 2007 Final EA that GHG significant adverse air quality impacts are not anticipated and, therefore, will not be further analyzed. Since no new significant adverse air quality impacts were identified, no mitigation measures are necessary or required.

Based upon these considerations, the proposed project would not make substantially worse any significant adverse air quality or GHG impacts detailed in the 2007 Final EA, significant adverse adverse air quality or GHG emission impacts are not anticipated and, therefore, an addendum is the appropriate. Since no significant or substantially worse adverse adverse air quality or GHG emission impacts were identified, no mitigation measures are necessary or required.

[4] Does not include indirect GHG emissions from power plants or emergency engines.

Biological Resources
PAR 1110.2 includes the same NOx concentration limits for biogas-fueled ICEs that would have become effective July 1, 2012, if the technology review had been completed in 2010. The current proposal would extend the effective final NOx compliance dates to January 1, 2016 or January 1, 2018 under the alternative compliance option. The analysis of biological impacts from PAR 1110.2 would be same as those identified for the 2008 amendments to Rule 1110.2, which were not deemed significant in the 2007 Final EA. As stated in the 2007 Final EA all construction and operational impacts would occur on existing facilities. Any impacts to biological resources would only occur at a later date.

The flaring of biogas in lieu of complying with PAR 1110.2 was not evaluated in the 2007 Final EA. Any flaring of biogas in lieu of complying with PAR 1110.2 would occur at existing affected facilities using existing onsite flares. For fire safety reasons, the area around biogas-fueled flares is devoid of biological activity. Affected operators that flare biogas in lieu of complying with PAR 1110.2 may remove biogas-fueled ICEs. PAR 1110.2 may result in the early removal of the biogas-fueled engines, but the impacts would be the same as removing them at a later date. The removal of the biogas-fueled engines is not expected to affect biological resources since the engines are placed on concrete pads and the area around the ICEs would be void of biological activity for fire safety reasons.

Existing digester gas facilities have emergency standby generators that can be used to support the plant during emergencies if the biogas-fueled engines are replaced by flares. Landfill gas facilities typically do not use emergency standby generators. The 2007 Final EA assumed that emergency engines would be installed at digester gas facilities that replaced their ICEs with alternative technologies in lieu of complying with the existing rule. If emergency engines are installed at an affected facility, the impacts would be no greater than those analyzed in the April 20, 2007 NOP/IS for the 2007 Final EA. Therefore, no new impacts are expected to biological resources from emergency standby generators. The removal of the biogas-fueled engines is not expected to affect biological resources since the engines would be placed on existing concrete surfaces within the boundaries of existing biogas facilities and the area around the emergency standby generators would be void of biological activity for fire safety reasons.

As explained above, PAR 1110.2 would not create a new significant adverse effect or make an existing adverse impact substantially worse, either directly or through habitat modifications, on any species identified as a candidate, sensitive, or special status species in local or regional plans, policies, or regulations, or by the California Department of Fish and Game or U.S. Fish and Wildlife Service; have a new substantial adverse effect on any riparian habitat or other sensitive natural community identified in local or regional plans, policies, or regulations, or by the California Department of Fish and Game or U.S. Fish and Wildlife Service; have a new substantial adverse effect on federally protected wetlands as defined by §404 of the Clean Water Act (including, but not limited to, marsh, vernal pool, coastal, etc.) through direct removal, filling, hydrological interruption, or other means; interfere substantially with the movement of any native resident or migratory fish or wildlife species or with established native resident or migratory wildlife corridors, or impede the use of native wildlife nursery sites; conflict with any local policies or ordinances protecting biological resources, such as a tree preservation policy or ordinance; or conflict with the provisions of an adopted Habitat Conservation plan, Natural Community Conservation Plan, or other approved local, regional, or state habitat conservation plan.

Based upon these considerations, the proposed project would not make substantially worse any significant adverse biological resource impacts detailed in the 2007 Final EA, significant adverse biological resources impacts are not anticipated and, therefore, an addendum is the appropriate. Since no significant or substantially worse adverse adverse biological resources impacts were identified, no mitigation measures are necessary or required.

Cultural Resources

PAR 1110.2 includes the same biogas concentration limits for biogas-fueled ICEs that would have become effective July 1, 2012, if the technology review had been completed in 2010. The current proposal would extend the effective final NOx compliance dates to January 1, 2016 or January 1, 2018 under the alternative compliance option. The analysis of cultural impacts from PAR 1110.2 would be the same as identified for the 2008 amendments to Rule 1110.2, which were not deemed significant for adverse cultural impacts in the April 20, 2007 NOP/IS for the 2007 Final EA. Any impacts to cultural resources would only occur at a later date.

The flaring of biogas in lieu of complying with PAR 1110.2 was not evaluated in the 2007 Final EA. All biogas flaring in lieu of complying with PAR 1110.2 would occur at existing affected facilities using existing biogas-fueled flares. If an operator flares biogas in lieu of complying with PAR 1110.2, they may also choose to remove the existing biogas-fueled ICEs. PAR 1110.2 may result in the early removal of the biogas-fueled engines, but the impacts would be the same as removing them at a later date. Demolition of biogas-fueled ICEs, is not expected to affect cultural resources, since the area around the biogas-fueled ICEs would have been previously disturbed (area graded, concrete slabs laid and ICEs and support equipment installed) to install the ICEs.

Existing digester gas facilities have emergency standby generators that can be used to support the plant during emergencies, if the biogas-fueled engines are replaced by flares. Landfill gas facilities typically do not use emergency standby generators. The 2007 Final EA assumed that emergency engines would be installed at digester gas facilities that replaced their ICEs with alternative technologies in lieu of complying with the existing rule. If emergency engines are installed at an affected facility, the impacts would be no greater than those analyzed in the 2007 Final EA. If new emergency standby generators are needed they are expected to be dropped in place within the boundaries of existing biogas facilities. Therefore, no new impacts are expected to cultural resources from emergency standby generators.

As explained above, PAR 1110.2 would not create a new significant adverse change in the significance of a historical resource as defined in §15064.5; cause a new substantial adverse change in the significance of an archaeological resource as defined in §15064.5; directly or indirectly destroy a unique paleontological resource, site, or feature; disturb any human including those interred outside formal cemeteries.

Based upon these considerations, the proposed project would not make substantially worse any significant adverse cultural resource impacts detailed in the 2007 Final EA, significant adverse cultural resources impacts are not expected from implementing PAR 1110.2; therefore, an addendum is appropriate. Since no significant or substantially worse adverse cultural resources impacts were identified, no mitigation measures are necessary or required.

Energy Impacts

PAR 1110.2 would include the same biogas NOx concentration limits previously proposed for July 1, 2012 with effective dates that extend out to January 1, 2016 or January 1, 2018 under the alternative compliance option. As a result, potential adverse energy impacts associated with compliance options for biogas-fueled ICEs would be same as impacts analyzed for the 2008 proposed amendments to Rule 1110.2 in the 2007 Final EA, but energy impacts, which were deemed less than significant would be expected to occur at a later date.

Electricity Impacts

The use of after treatment on ICEs was assumed to reduce efficiency of some ICEs due to pressure drops caused by the control devices. The 2007 Final EA concluded that this would result in a minor loss of electricity production (1,706 megawatt hours per year).

Alternative technologies used in lieu of complying with PAR 1110.2 (boilers, turbines and microturbines) generate more waste heat that ICEs, which reduces the amount of electricity produced. Replacing biogas-fueled ICEs with microturbines alone was determined to result in the greatest loss of electricity production (101,013 megawatt hours per year). The analysis in the 2007 Final EA assumed if an operator replaced ICEs with either a gas turbine and LNG plant or a microturbine and an LNG Plant, all electricity production would be lost and additional electricity from the power grid would be required to operate the LNG plant. The scenario where ICEs are replaced with microturbines at digester gas facilities and LNG plants at landfill gas facilities was estimated to result in a loss in electricity production and increased demand for electricity to operate the LNG plant of 404,133 megawatt hours per year. Adding the electricity production loss from replacing biogas-fueled ICEs with LNG plants to the electricity production loss from replacing non-biogas engines with electric motors (171,827 megawatt hours per year), the 2007 Final EA estimated that the worst-case electrical energy production loss would be 576,527 megawatt hours per year. However, a 576,527 megawatt hour per year loss was not deemed significant because it would be less than one percent of the 120,194 gigawatt hours per year available in southern California reported in the Final Program EIR for the 2007 AQMP.

Flaring biogas in lieu of complying with PAR 1110.2 was not evaluated in the 2007 Final EA because it was assumed that most operators would not choose to flare biogas, since electricity or heat generated by biogas-fueled ICEs is typically used to power operations onsite or, if electricity is produced in excess of onsite needs, sold to local utilities to be used offsite. Flaring of biogas in lieu of complying with PAR 1110.2 would likely occur at facilities where the quality of the biogas is poor (e.g., closed landfills) and/or the existing ICEs are at the end of their useful life, since it may not be cost effective to install after treatment or replacement engines with alternative technologies (biogas turbines, microturbines, biogas to LNG plants) once biogas concentrations become poor. Biogas flares would still be required as a safety measure at landfills with poor biogas concentrations.

If all biogas-fueled ICEs are replaced by flares, according to the 2007 Final EA, approximately 437,214 megawatt hours per year of energy production would be lost. The electricity loss from non-biogas-fueled ICEs identified in the 2007 Final EA was 171,827 megawatt hours per year, which would not be affected by PAR 1110.2. Therefore, the total loss of electricity from the non-biogas-fueled ICE requirements 2008 amendments to Rule 1110.2 and the current PAR 1110.2 if all biogas were flared would be 609,041 megawatt hours per year. This too would be less than one percent (0.5 percent) of the 120,194 gigawatt hours per year available in southern

California reported in the Final Program EIR for the 2007 AQMP. Therefore, if all biogas at closed landfills was flared in lieu of complying with the biogas portion of PAR 1110.2, energy impacts from implementing PAR 1110.2 would remain not significant.

Natural Gas Impacts

It was concluded in the 2007 Final EA that the 2008 amendments to Rule 1110.2 would result in a reduction of natural gas use because of the electrification of some of the non-biogas-fueled engines in lieu of complying with the amendments. If an operator uses the efficiency correction factor the amount of natural gas used in biogas-fueled engines would be restricted to 10 percent of the gas consumed in the existing ICEs. Once the biogas concentration limits become effective, there would be no limit on the percentage of natural gas burned in the 2008 amendments to Rule 1110.2. The proposed project would continue to allow the percentage of natural gas in the combustion fuel to be unrestricted once an affected ICE complies with the concentration limits of PAR 1110.2. Therefore, PAR 1110.2 is not expected to change the conclusion of no significant adverse natural gas impacts.

Flaring biogas in lieu of complying with PAR 1110.2 was not evaluated in the 2007 Final EA. Any biogas flaring in lieu of affected engines complying with PAR 1110.2 would occur in existing biogas-fueled flares. Since flaring would occur in existing biogas-fueled flares (all affected facilities have backup flares in the event of a shutdown of the affected engine), and flares can burn lower quality biogas than ICEs, flaring biogas in lieu of complying with PAR 1110.2 is likely to result in less natural gas use.

If the biogas-fueled engines are replaced by flares, digester gas facilities have emergency standby generators that can be used to support the plant during emergencies. Landfill gas facilities typically do not use emergency standby generators. Therefore, no new emergency standby generators are expected. However, if new emergency standby generators are needed they are expected to be dropped in place within the boundaries of existing biogas facilities. The 2007 Final EA estimated that approximately 5,023 millon btu per year (0.013 millon cubic feet per day) may be required at a single facility to fuel new emergency standby generators. The 2007 Final EA for the AQMP states that 1,474 millon cubic feet of natural per day is used in the industrial sector in California. The consumption of 0.013 millon cubic feet per day would be less than one percent (0.0009 percent) of the California industrial daily consumption, which is not considered significant.

Diesel Fuel Impacts

Additional diesel fuel was expected to be consumed during construction; from trips related to source testing, delivery, or hauling away of spent carbon or catalysts; and by diesel emergency generators depending on whether operators would comply with PAR 1110.2 or replace existing biogas-fueled ICEs with an alternative technology. It was determined in the 2007 Final EA that the maximum 3,218 gallons of diesel that may be consumed per day would be less than one percent (0.02 percent) of the 10 million gallons of diesel used in California and, therefore, was not considered to be significant.

The flaring of biogas in lieu of complying with PAR 1110.2 was not evaluated in the 2007 Final EA. All biogas flaring in lieu of complying with PAR 1110.2 would occur in existing biogas-fueled flares. In spite of the delay in emission limits for biogas fueled PAR 1110.2 may result in the early removal of biogas-fueled ICEs, if operators choose to flare biogas in lieu of complying with PAR 1110.2. However, the removal of ICEs was included in the diesel fuel construction estimate in the 2007 Final EA, which determined diesel fuel impacts not to be significant. Existing digester facilities are expected to have emergency generators that can operate essential services at the facilities during emergencies. Landfill gas facilities do not use emergency generators. Therefore, no additional diesel is expected to be used. However, the use of diesel fuel (202 gallons per day) if facilities had to install new diesel emergency engines was evaluated in the 2007 Final EA, which determined diesel fuel impacts not to be significant.

Renewable Resource Impacts

Biogas is considered a renewable energy resource. Currently biogas-fueled ICEs generate electricity that is either used at the biogas facilities, sold to the electricity grid, or some combination of the two.

In-state renewable electricity generation (30,005 GWh) in California is 14.6 percent of the total electricity generated (205,018 GWh) in 2010.[5] In-state electricity from biomass (5,745 GWh) represents about 17 percent of the total renewable electricity capacity (30,005 GWh) in California. Of this 17 percent, approximately 32 percent of electricity produced from biopower is produced from the combustion of landfill (28 percent) and digester gas (four percent).[6] Senate Bill 1078 (SB 1078, Sher, Chapter 516, Statutes of 2002) established the California Renewables Portfolio Standard (RPS) program, which requires an annual increase in renewable generation by the utilities equivalent to at least one percent of sales, with an aggregate goal of 20 percent by 2017. In 2006, this target date was accelerated to 2010, and in 2011 the RPS was revised to require that renewable electricity should equal an average of 20 percent of the total electricity sold to retail customers in California during the compliance period ending December 31, 2013, 25 percent by December 31, 2016, and 33 percent by December 31, 2020.

It is assumed for this analysis that operators of biogas-fueled ICEs would flare biogas in lieu of complying with PAR 1110.2. The quality of landfill gas decreases after landfills close. In the long term operators of biogas-fueled ICEs at closed landfills may need to flare biogas instead of installing after treatment on existing biogas-fueled ICEs or replacing the ICEs with alternative technologies because the quality of the landfill gas (methane content) declines to the point where biogas-fueled ICEs cannot combust the landfill gas to provide electricity, whereas flares would still be able to combust the landfill gas at low methane content levels. Since it is likely that biogas-fueled ICEs at closed landfills would eventually be replaced with flares anyway when the landfill gas quality becomes poor, PAR 1110.2 may only result in an earlier transition from burning biogas in engines to burning biogas in flares.

Based on a conversation with CEC staff,[7] SCAQMD staff used the California Biomass Collective's biomass facility database to estimate the gross capacity in megawatts of ICEs at closed landfills. Based on closure information in the CalRecycle Solid Waste Information System[8] and capacity data in biomass facility database approximately 29.9 megawatts of

---

[5] CEC, Energy Almanac, Total Electricity System Power, 2010 Total System Power in Gigawatt Hours http://energyalmanac.ca.gov/electricity/ total_system_power.html

[6] CEC, Table 2-3: Summary of In-State Biopower Capacity, 2011 Bioenergy Action Plan, CEC-300-2011-001-CTF, March 2011, http://www.energy.ca.gov/2011publications/CEC-300-2011-001/CEC-300-2011-001-CTF.PDF

[7] Conversation with Mr. Prab Sethi of the CEC on March 14, 2012.

[8] CalRecycle, Solid Waste Information System, http://www.calrecycle.ca.gov/SWFacilities/Directory/, March 14, 2012

capacity[9] is available at closed landfills in the district. The 2011 Bioenergy Action Plan estimates that there was 1,528 megawatts of bioenergy capacity in 2010 with another 1,311 megawatts in proposed projects for a total of 2,839 megawatts of capacity by the end of 2012. The 29.9 megawatts of capacity at closed biogas facilities would be less than one percent (0.5 percent) of the 2,839 megawatts of bioenergy expected by the end of 2012. It is conservative to assume that capacity at all closed biogas facilities would be lost because of flaring in lieu of complying with PAR 1110.2. Based on the CEC's December 2011 Lead Commissioner Report – Renewable Power in California: Status and Issues,[10] new photovoltaic, solar thermal and wind projects are expected to generate most of the renewable energy in California (see Table 6). Therefore, based on the above analysis, the amount of renewable energy lost because of operators flaring biogas in lieu of complying with PAR 1110.2 is not expected to generate a significant adverse impact or make substantially worse a significant adverse impact to renewable energy.

Table 6
Renewable Projects Permitted in 2010 by California County (in Megawatts)

County	Bio	Cogen	Geo	Photo-voltaic >20MW	Photo-voltaic <20MW	Solar Thermal	Photo-voltaic/ Solar Thermal	Wind	Total
Imperial			208	1,259					1,467
Kern	44			867	24	250		2,169	3,354
Kings				145					145
Los Angeles		85		337					422
Riverside				175		1,734			1,909
Sacramento					2				2
San Bernardino				20		770	633		1,423
San Diego				45					45
San Luis Obispo				250					250
Shasta								102	102
Solano								155	155
Stanislaus				50	1				51
Tulare				110					110
Total	44	85	208	3,258	27	2,754	633	2,426	9,435

Source: CEC, Lead Commissioner Report – Renewable Power in California: Status and Issues, CEC-150-2011-002-LCF-REV1, December 2011.

As explained above, the PAR 1110.2 would not conflict with adopted energy conservation plans; result in the need for new or substantially altered power or natural gas utility systems; create any significant effects on local or regional energy supplies and on requirements for additional energy; create any significant effects on local or regional energy supplies and on requirements

[9] California Biomass Collective's biomass facility database , http://biomass.ucdavis.edu/tools/, March 14, 2012,
[10] CEC, Lead Commissioner Report – Renewable Power in California: Status and Issues, CEC-150-2011-002-LCF-REV1, December 2011

for additional energy; create any significant effects on peak and base period demands for electricity and other forms of energy; and would comply with existing energy standards.

Based upon these considerations, the proposed project would not substantially alter the significant adverse energy impacts detailed in the 2007 Final EA; significant adverse impacts to energy are not expected from implementation of PAR 1110. Since PAR 1110.2 would not generate any new significant energy impacts or make substantially worse any significant adverse impacts, an addendum is appropriate. Since no significant or substantially worse adverse energy impacts were identified, no mitigation measures are necessary or required.

Geology and Soils

PAR 1110.2 includes the same biogas concentration limits for biogas-fueled ICEs that would have become effective July 1, 2012, if the technology review had been completed in 2010. The current proposal would extend the effective final NOx compliance dates to January 1, 2016 or January 1, 2018 under the alternative compliance option. The analysis of geology and soils impacts would be the same as proposed in the 2008 amendments to Rule 1110.2, which were not deemed significant for adverse geology and soils impacts in the April 20, 2007 NOP/IS for the 2007 Final EA. Any impacts to geology and soils would only occur at a later date.

Flaring biogas in lieu of complying with PAR 1110.2 was not analyzed in the 2007 Final EA. However, any flaring of biogas in lieu of complying with PAR 1110.2 would occur at existing affected facilities using existing biogas-fueled flares. Therefore, no construction would be required. Affected operators that flare biogas in lieu of complying with PAR 1110.2 may remove biogas-fueled ICEs. PAR 1110.2 may result in the early removal of the biogas-fueled engines, but the impacts would be the same as removing them at a later date. The removal of the biogas-fueled engines is not expected to affected geology and soils since the engines are placed on concrete pads.

Existing digester gas facilities have emergency standby generators that can be used to support the plant during emergencies, if the biogas-fueled engines are replaced by flares. Landfill gas facilities typically do not use emergency standby generators. The 2007 Final EA assumed that emergency engines would be installed at digester gas facilities that replaced their ICEs with alternative technologies in lieu of complying with the existing rule. If emergency engines are installed at an affected facility, the impacts would be no greater than those analyzed in the 2007 Final EA. Therefore, no new impacts are expected to geological resources from emergency standby generators. However, if new emergency standby generators are needed they are expected to be dropped in place on existing concrete surfaces within the boundaries of existing biogas facilities.

As explained above, the PAR 1110.2 would not expose people or structures to potential new significant adverse effects, including the risk of loss, injury, or death involving ruptures of a known earthquake fault, strong seismic ground shaking or seismic-related ground failure, including liquefaction; result in new substantial soil erosion or the loss of topsoil; be located on a geologic unit or soil that is unstable or that would become unstable as a result of the project, and potentially result in new on- or off-site landslide, lateral spreading, subsidence, liquefaction or collapse; be located on expansive soil, as defined in Table 18-1-B of the Uniform Building Code (1994), creating substantial risks to life or property; or have soils incapable of adequately supporting the use of septic tanks or alternative wastewater disposal systems where sewers are not available for the disposal of wastewater.

Based upon these considerations, since the proposed project is not expected to adversely affect geology or soils in any way, it would not alter the significant adverse geology and soil impacts conclusion in the 2007 Final EA. Since no significant or substantially worse adverse geology and soils impacts were identified, no mitigation measures are necessary or required.

Hazards and Hazardous Materials

PAR 1110.2 includes the same biogas concentration limits for biogas-fueled ICEs that would have become effective July 1, 2012, if the technology review had been completed in 2010. The current proposal would extend the effective final NOx compliance dates to January 1, 2016 or January 1, 2018 under the alternative compliance option. The analysis of hazards and hazardous material impacts would be the same as proposed in the 2008 amendments to Rule 1110.2, which were not deemed significant for hazards and hazardous material impacts in the 2007 Final EA. Any hazards or hazardous materials impacts would only occur at a later date.

Additional diesel fuel was expected to be consumed during construction; from trips related to source testing, delivery, or hauling away of spent carbon or catalysts; and by diesel emergency generators depending on whether operators would comply with 2008 amendments to Rule 1110.2 or replace existing biogas-fueled ICEs with an alternative technology. The 2007 Final EA concluded that hazard impacts associated with additional diesel use would not be significant. Flaring in lieu of complying with PAR 1110.2 would eliminate the need for diesel during construction and trips related to source testing, delivery, or hauling away of spent carbon or catalysts. As a result, potential hazards associated with diesel used as a mobile source fuel would be less under PAR 1110.2 than was analyzed in the 2007 Final EA.

Similarly, potential hazard impacts from biogas-fueled ICEs that would have complied with 2008 amendments to Rule 1110.2 using SCR units using either aqueous ammonia or urea to operate would be eliminated under the proposed project. Delivery of ammonia for SCR units would no longer be necessary. The 2007 Final EA concluded that a catastrophic release of ammonia from storage tanks could result in significant adverse exposures to ammonia vapors. If flaring of biogas is chosen in lieu of complying with PAR 1110.2, no ammonia would be used. Therefore, hazard impacts from ammonia handling, storage or transportation would be less under PAR 1110.2 than was analyzed in the 2007 Final EA.

In the 2007 Final EA, SCAQMD staff concluded that a cataclysmic destruction of an LNG storage tank in an LNG facility system would extend 0.2 mile from the LNG storage tank, which was considered to be a significant adverse impact because offsite receptors were determined to be within 0.1 mile of some affected facilities. Similarly, during transport of LNG, it was estimated that the adverse impacts from various releases could extend 0.3 mile, which was also concluded to be a significant adverse hazard impact. If flaring natural gas is chosen in lieu of complying with PAR 1110.2 hazard impacts identified in the 2007 Final EA from storing LNG at affected facilities or from transporting LNG would be eliminated.

Flaring biogas in lieu of complying with PAR 1110.2 was not analyzed in the 2007 Final EA. However, any flaring of biogas used in lieu of complying with PAR 1110.2 would occur at existing affected facilities using in existing biogas-fueled flares. Since biogas would be flared on-site, there would be no hazards associated with transportation. Combustion of biogas in a flare or ICEs is considered a safety measure that prevents releases of biogas into environment, since it would prevent a build-up of biogas at landfills or sewage treatment facilities. The flares are considered a means of controlling biogas during upsets in the existing ICEs.

Existing digester gas facilities have emergency standby generators that can be used to support the plant during emergencies, if the biogas-fueled engines are replaced by the flaring of biogas. Landfill gas facilities typically do not use emergency standby generators. The 2007 Final EA assumed that affected facility operators would install emergency engines at digester gas facilities that replaced their ICEs with alternative technologies in lieu of complying with the existing rule. If emergency engines are installed at an affected facility, the impacts would be no greater than those analyzed in the 2007 Final EA. Therefore, no new hazards or hazardous material impacts are expected from emergency standby generators. The 2007 Final EA estimated that approximately six gallons of diesel fuel per day or 194 millon cubic feet per day of natural gas may be required at a single facility to fuel new emergency standby generators. Because of its low vapor pressure, hazards from the transportation or handling of diesel fuel were concluded to be less than significant. Implementing PAR 1110.2 would not change this conclusion. New natural gas emergency standby generators are expected to be used at facilities that already have natural gas service; therefore, no new hazards are expected from the use of natural gas to fuel new emergency standby generators.

As explained above, PAR 1110.2 is not expected to create a significant new or additional hazard to the public or create a reasonably foreseeable upset condition involving the release of hazardous materials greater than what was reported in the 2007 Final EA.

Government Code §65962.5 refers to hazardous waste handling practices at facilities subject to the Resources Conservation and Recovery Act (RCRA). Though some of the affected facilities subject to 2008 amendments to Rule 1110.2 may be included on the list of the hazardous materials sites compiled pursuant to Government Code §65962.5, compliance with the proposed project is not expected to affect in any way any facility’s current hazardous waste handling practices. Hazardous wastes from the existing facilities are required to be managed in accordance with applicable federal, state, and local rules and regulations. As a result, the NOP/IS for the 2007 Final EA concluded that potential hazard impacts at any affected facilities subject to Government Code §65962.5 would be less than significant. Since PAR 1110.2 would not require construction such as the installation of control equipment utilizing catalysts (that could later be processed as hazardous waste), no additional waste is expected to be generated from the proposed project. Further, for those affected facilities which already use catalyst, the collected spent catalyst would continue to be handled in the same manner under PAR 1110.2 as currently handled such that it would be disposed/recycled at approved facilities. Consequently, hazards impacts from the disposal/recycling of hazardous materials as a result of implementing PAR 1110.2 would not change the significance conclusion in the NOP/IS for the 2007 Final EA.

Airports and Airstrips

The 2007 Final EA concluded that, because of the potential for significant adverse impacts from storing or transport of ammonia or LNG could occur within two miles of an airport or airstrip, it was concluded that impacts to these types of facilities would be significant. However, as explained above, flaring biogas instead of complying with the PAR 1110.2 would be expected to reduce this significant impact somewhat. Therefore, PAR 1110.2 is not expected to result in a greater safety hazard impacts for people residing or working in an affected facility project area that is within the vicinity of an airport than disclosed in the 2007 Final EA.

Emergency Response Plans
The NOP/IS for the 2007 Final EA concluded that impacts to local emergency response plans would not be significant. Emergency response plans are typically prepared in coordination with the local city or county emergency plans to ensure the safety of not only the public (surrounding local communities), but the facility employees as well. The proposed project is not expected to impair implementation of, or physically interfere with any adopted emergency response plan or emergency evacuation plan. Any existing facilities affected by the proposed project would typically already have their own emergency response plans in place. Since existing facilities currently flare biogas, any additional flaring of biogas is expected to fall within procedures found in existing emergency response plans. Thus, PAR 1110.2 is not expected to impair implementation of or physically interfere with an adopted emergency response plan or emergency evacuation plan, so it would not change the conclusion of insignificance for this topic in the NOP/IS for the 2007 Final EA.

Flammable Materials and Fire Hazards
The NOP/IS for the 2007 Final EA concluded that wildfire risk impacts from the 2008 amendments to Rule 1110.2 would not be significant since existing biogas-fueled ICEs would not be expected to increase the use of flammable materials in or near areas with flammable brush, grass, or trees because operators of affected facilities would not alter the type or amount of fuel used when replacing or retrofitting engines. In addition, affected facilities are often located in urbanized, industrial areas and no wildlands are expected to be located in the immediate or surrounding areas. Finally, no substantial or native vegetation is expected to exist within the operational portions of any of the affected facilities, since existing ICE systems are operating at these facilities. Flaring biogas in lieu of complying with PAR 1110.2 is not expected to alter the conclusion in the NOP/IS that wildfire risk impacts would be less than significant.

It was concluded in the NOP/IS for the 2007 Final EA that the 2008 amendments to Rule 1110.2 would not create significant adverse flammability impacts because none of the control technologies or monitoring equipment is expected to use flammable materials (aqueous ammonia is not flammable). Further, the 2008 amendments to Rule 1110.2 would not require a change in operation, fuels consumed or stored. Flaring biogas in lieu of complying with PAR 1110.2 would not alter the conclusion in the NOP/IS because no additional fuels or flammable materials are associated with flaring biogas.

Based upon these considerations, the proposed project would not substantially alter the significant adverse hazards and hazardous materials impacts identified in the NOP/IS for the 2008 amendments to Rule 1110.2 or the 2007 Final EA because no new significant or substantially worse hazards and hazardous materials impacts are expected from the implementation of PAR 1110.2; therefore, an addendum is appropriate. Since no significant or substantially worse hazards and hazardous materials impacts were identified, no mitigation measures are necessary or required.

Hydrology and Water Quality

The NOP/IS for the 2007 Final EA concluded that hydrology and water quality from implementing the 2008 amendments to Rule 1110.2 impacts would not be significant. PAR 1110.2 includes the same biogas concentration limits for biogas-fueled ICEs that would have become effective July 1, 2012, if the technology review had been completed in 2010. The current proposal would extend the effective final NOx compliance dates to January 1, 2016 or January 1, 2018 under the alternative compliance option. The analysis of hydrology and water quality impacts would be the same as proposed in the 2008 amendments to Rule 1110.2, which were not deemed significant for adverse hydrology and water quality impacts in the 2007 Final EA. Any hydrology or water quality impacts would only occur at a later date.

Flaring biogas in lieu of complying with PAR 1110.2 was not analyzed in the 2007 Final EA. However, any flaring of biogas in lieu of complying with PAR 1110.2 would occur in existing biogas-fueled flares. Any increase in flaring of biogas is not expected to require any new or additional water use or wastewater discharge because flares typically do not involve the use of water. Therefore, PAR 1110.2 would not adversely affect water resources, water quality standards, groundwater supplies, water quality degradation, existing water supplies or wastewater treatment facilities.

Because the affected engines and after treatments in PAR 1110.2 do not utilize water for their operations, no changes to any existing wastewater treatment permits would be necessary. As a result, the proposed project is not expected to affect any affected facility's ability to comply with existing wastewater treatment requirements or conditions from any applicable Regional Water Quality Control Board or local sanitation district because the proposed project has no effect on existing wastewater generation.

The NOP/IS for the 2007 Final EA concluded that any construction activities requiring water for dust suppression for the installation of after treatment or removal of equipment would be minor and, therefore, would not require substantial amounts of water. Any disposal of existing ICEs as a result of flaring in lieu of complying with PAR 1110.2 is not expected to require using any water or generate any wastewater. The disposal of existing ICEs is not expected to require earthmoving, ICEs are on existing concrete pads, so additional watering for fugitive dust control pursuant to Rule 403 would be not necessary for PAR 1110.2. As a result, PAR 1110.2 would not alter the conclusions in the NOP/IS that the 2008 amendments to Rule 1110.2 would not have significant adverse effects on any existing drainage patterns, increase the rate or amount of surface runoff water that would exceed the capacity of existing or planned stormwater drainage systems.

The NOP/IS for the 2007 Final EA concluded that the 2008 amendments to Rule 1110.2 would not be not expected to require any new or additional construction activities to build additional housing that could be located in 100-year flood hazard areas. Similarly, PAR 1110.2 is not expected to result in placing housing in 100-year flood hazard areas that could create new flood hazards. Since there is no new or additional construction associated with PAR 1110.2, the proposed project is not expected to alter the conclusion of insignificance regarding placing housing in a 100-year flood zone in the NOP/IS.

The NOP/IS for the 2007 Final EA concluded that the 2008 amendments to Rule 1110.2 would not create significant adverse risk impacts from seiches, tsunamis, or mudflows. PAR 1110.2

would only delay the installation of after treatment on affected engines or alternative technologies used in lieu of complying with PAR 1110.2. No new facilities are expected to be constructed as a result of the proposed project. Thus, no new flood risks or risks from seiches, tsunamis or mudflow conditions would result from the implementation of PAR 1110.2. Further, any risks from seiches, tsunamis, or mudflows would be part of the existing setting. Consequently, PAR 1110.2 would not alter any conclusions in the NOP/IS regarding risks from seiches, tsunamis, or mudflows.

The NOP/IS for the 2007 Final EA concluded that the 2008 amendments to Rule 1110.2 would not create significant adverse impacts to wastewater or stormwater drainage facilities. Because the engines subject to PAR 1110.2 and emissions control equipment do not utilize water for their operations, no new or increase in wastewater that could exceed the capacity of existing stormwater drainage systems or require the construction of new wastewater or stormwater drainage facilities would be expected as a result of complying with the proposed project. Biogas facilities currently manage stormwater; no change in stormwater management would be expected. Consequently, PAR 1110.2 would not alter any conclusions in the NOP/IS regarding affects to wastewater or stormwater drainage facilities.

Based upon these considerations, the proposed project would not substantially alter the conclusions in the NOP/IS that significant adverse hydrology and water quality impacts, since significant or substantially worse hydrology and water quality impacts are not expected from the implementation of the 2008 amendments to Rule 1110.2; therefore, an addendum is appropriate. Since no significant or substantially worse hydrology and water quality impacts were identified, no mitigation measures are necessary or required.

Land Use and Planning

The NOP/IS for the 2007 Final EA concluded that land use and planning impacts would not be significant. PAR 1110.2 includes the same biogas NOx concentration limits for biogas-fueled ICEs that would have become effective July 1, 2012, if the technology review had been completed in 2010. The current proposal would extend the effective final NOx compliance dates that extend out to January 1, 2016 or January 1, 2018 under the alternative compliance option. PAR 1110.2 would only delay the installation and use of emissions control after treatment for stationary engines fired by biogas or replacement of ICEs in lieu of complying with PAR 1110.2. All construction and operations activities are expected to occur on-site at biogas facilities. Therefore, the proposed project is not expected alter any conclusions in the NOP/IS that the 2008 amendments to Rule 1110.2 would not create divisions in any existing communities.

The NOP/IS for the 2007 Final EA concluded that the 2008 amendments to Rule 1110.2 would not create significant adverse land use and planning impacts. There are no provisions in PAR 1110.2 that would affect land use plans, policies, or regulations. Land use and other planning considerations are determined by local governments, and since PAR 1110.2 would only affect biogas-fueled engines, no land use or planning requirements would be altered by the proposed project. Further, PAR 1110.2 would be consistent with the typical industrial, commercial, and institutional zoning of the affected facilities. Operations of affected engines at biogas facilities would still be expected to comply, and not interfere, with any applicable land use plans, zoning ordinances, habitat conservation or natural community conservation plans.

Based upon these considerations, the proposed project would not substantially alter the significant adverse land use and planning impacts detailed in the 2007 Final EA, since significant or substantially worse land use and planning impacts are not expected from the implementation of PAR 1110.2;therefore, an addendum is appropriate. Since no significant or substantially worse land use and planning impacts were identified, no mitigation measures are necessary or required.

Mineral Resources

The NOP/IS for the 2007 Final EA concluded that material resource impacts would not be significant. PAR 1110.2 includes the same biogas NOx concentration limits for biogas-fueled ICEs that would have become effective July 1, 2012, if the technology review had been completed in 2010. The current proposal would extend the effective final NOx compliance dates that extend out to January 1, 2016 or January 1, 2018 under the alternative compliance option. PAR 1110.2 would only delay the installation and use of emissions control after treatment for stationary engines fired by biogas or replacement of ICEs in lieu of complying with PAR 1110.2. All construction and operations activities are expected to occur on-site at biogas facilities. Therefore, the proposed project is not expected alter any conclusions in the NOP/IS that the 2008 amendments to Rule 1110.2 would not result in the loss of availability of a known mineral resource of value to the region and the residents of the state such as aggregate, coal, clay, shale, et cetera, or of a locally-important mineral resource recovery site delineated on a local general plan, specific plan or other land use plan.

Based upon these considerations, the proposed project would not substantially alter the significant adverse mineral resource impacts detailed in the 2007 Final EA, since significant or substantially worse mineral resources impacts are not expected from the implementation of PAR 1110.2; therefore, an addendum is appropriate. Since no significant or substantially worse mineral resources impacts were identified, no mitigation measures are necessary or required.

Noise

The NOP/IS for the 2007 Final EA concluded that noise impacts would not be significant. PAR 1110.2 includes the same biogas NOx concentration limits for biogas-fueled ICEs that would have become effective July 1, 2012, if the technology review had been completed in 2010. The current proposal would extend the effective final NOx compliance dates that extend out to January 1, 2016 or January 1, 2018 under the alternative compliance option. PAR 1110.2 would only delay the installation and use of emissions control after treatment for stationary engines fired by biogas or replacement of ICEs in lieu of complying with PAR 1110.2. All construction and operations activities are expected to occur on-site at biogas facilities, which are typically located in remote areas that are not adjacent to residences. Therefore, the proposed project is not expected alter any conclusions in the NOP/IS that the 2008 amendments to Rule 1110.2 would not create new noise or vibration impacts.

Operation of affected biogas-fueled engines typically results in the generation of a certain amount of noise and vibration. However, it is expected that affected engines fired by biogas are already in compliance with all existing noise control laws or ordinances. Further, Occupational Safety and Health Administration (OSHA) and California-OSHA (Cal/OSHA) have established noise standards to protect worker health. The NOP/IS concluded that PAR 1110.2 compliant ICEs and any technology used in lieu of complying with PAR 1110.2 were not expected not generate additional or new noise, excessive groundborne vibration, or substantially increase ambient noise levels beyond existing levels. PAR 1110.2 would implement the concentration limits for biogas-fueled engines at a later date. Therefore, any noise from after treatment or technology used in lieu of complying with PAR 1110.2 required by the existing Rule 1110.2, which was not deemed to be significant in the 2007 Final EA, would only occur at a later date.

Flaring biogas in lieu of complying with PAR 1110.2 was not analyzed in the 2007 Final EA. However, flaring of biogas currently occurs at affected facilities; therefore, additional flaring of biogas, would not add any new noise, excessive groundborne vibration, or substantially increase ambient noise levels beyond existing levels.

Although not likely, some of the facilities affected by PAR 1110.2 may be located at sites within an airport land use plan, or within two miles of a public airport, implementation of the proposed project would not expose people residing or working in the project area to the same degree of excessive noise levels associated with airplanes. All noise producing equipment must comply with local noise ordinances and applicable OSHA or Cal/OSHA workplace noise reduction requirements.

Based upon these considerations, the proposed project would not substantially alter the significant adverse noise impacts detailed in the 2007 Final EA, since significant or substantially worse noise impacts are not expected from the implementation of PAR 1110.2;therefore, an addendum is appropriate. Since no significant or substantially worse noise impacts were identified, no mitigation measures are necessary or required.

Population and Housing

The NOP/IS for the 2007 Final EA concluded that impacts to population and housing would not be significant. PAR 1110.2 includes the same biogas NOx concentration limits for biogas-fueled ICEs that would have become effective July 1, 2012, if the technology review had been completed in 2010. The current proposal would extend the effective final NOx compliance dates that extend out to January 1, 2016 or January 1, 2018 under the alternative compliance option. PAR 1110.2 would only delay the installation and use of emissions control after treatment for stationary engines fired by biogas or replacement of ICEs in lieu of complying with PAR 1110.2. All construction and operations activities are expected to occur on-site at biogas facilities. Therefore, the proposed project is not expected alter any conclusions in the NOP/IS that the 2008 amendments to Rule 1110.2 would not create new impacts to population or housing.

Human population within the SCAQMD's jurisdiction is anticipated to grow regardless of implementing PAR 1110.2. No component of PAR 1110.2 would require additional construction employees than was analyzed in the April 20, 2007 NOP/IS for the 2007 Final EA. Similarly, additional employees would not be required during operation because the proposed project would only delay the operation of after treatment or technology used in lieu of complying with PAR 1110.2.

District population is not expected to be affected directly or indirectly as a result of adopting and implementing PAR 1110.2. Further, PAR 1110.2 would not indirectly induce growth in the area of facilities with affected engines. The construction of single- or multiple-family housing units would not be required as a result of implementing the proposed project since no new employees would be required at affected facilities. The proposed project is not expected to require relocation of affected engines or facilities, so existing housing or populations in the district are not anticipated to be displaced necessitating the construction of replacement housing elsewhere. As a result, the proposed project is not anticipated to generate any significant adverse effects, either direct or indirect, on population growth in the district or population distribution.

Based upon these considerations, the proposed project would not substantially alter the significant adverse population and housing impacts detailed in the 2007 Final EA, since significant or substantially worse population and housing impacts are not expected from the implementation of PAR 1110.2; therefore, an addendum is appropriate. Since no significant or substantially worse population and housing impacts were identified, no mitigation measures are necessary or required.

Public Services

The NOP/IS for the 2007 Final EA concluded that impacts to public services would not be significant. As noted in the "Hazards and Hazardous Materials" discussion, PAR 1110.2 would not involve the use of any new acutely hazardous materials. As a result, no new fire hazards or increased use of hazardous materials would be introduced at existing affected facilities that would require emergency responders such as police or fire departments. Thus, no new demands for fire or police protection are expected from PAR 1110.2 since the proposed rule amendments would only delay the installation of emission control devices or technology used in lieu of complying with PAR 1110.2 and associated equipment.

As noted in the "Population and Housing" discussion, implementation of the proposed project would not require new employees for construction because no new or additional construction activities would be necessary to comply with PAR 1110.2 for affected engines beyond what was previously analyzed in the 2007 Final EA. Only the installation and operation of after treatment or replacement technology used in lieu of complying with PAR 1110.2 would take place at a later date. Similarly, no new employees would be required to maintain operation of the affected engines or alternative technologies other than what was evaluated previously in the 2007 Final EA. As a result, PAR 1110.2 would have no direct or indirect effects on population growth in the district. Therefore, there would be no increase in local population and thus no impacts are expected to local schools or parks.

Because the proposed project would only resulting in construction and operational activities occurring at a later date that may require new or altered permits, implementation of PAR 1110.2 would not trigger a need for additional government services than what was analyzed in the 2007 Final EA. Further, the proposed project would not result in the need for new or physically altered government facilities in order to maintain acceptable service ratios, response times, or other performance objectives. There would be no increase in population and, therefore, no need for physically altered government facilities.

Based upon these considerations, the proposed project would not substantially alter the significant adverse public service impacts detailed in the April 20, 2007 NOP/IS for the 2007 Final EA, since significant or substantially worse public services impacts are not expected from the implementation of PAR 1110.2;therefore, an addendum is appropriate. Since no significant or substantially worse public services impacts were identified, no mitigation measures are necessary or required.

Recreation

The NOP/IS for the 2007 Final EA concluded that recreation impacts would not be significant. As previously discussed under "Land Use," there are no provisions in PAR 1110.2 that would affect land use plans, policies, or regulations. Land use and other planning considerations are determined by local governments; no land use or planning requirements would be altered by the proposed project. Further, implementation of PAR 1110.2 would not increase the use of existing neighborhood and regional parks or other recreational facilities or include recreational facilities or require the construction or expansion of recreational facilities that might have an adverse physical effect on the environment because the proposed project is not expected to induce population growth.

Based upon these considerations, the proposed project would not substantially alter the significant adverse recreation impacts detailed in the 2007 Final EA, since significant or substantially worse recreation impacts are not expected from the implementation of PAR 1110.2 and, therefore, an addendum is appropriate. Since no significant or substantially worse recreation impacts were identified, no mitigation measures are necessary or required.

Solid and Hazardous Wastes

The NOP/IS for the 2007 Final EA concluded that solid and hazardous waste impacts would not be significant. PAR 1110.2 includes the same biogas NOx concentration limits for biogas-fueled ICEs that would have become effective July 1, 2012, if the technology review had been completed in 2010. The current proposal would extend the effective final NOx compliance dates that extend out to January 1, 2016 or January 1, 2018 under the alternative compliance option. PAR 1110.2 would only delay the installation and use of emissions control after treatment for stationary engines fired by biogas or replacement of ICEs in lieu of complying with PAR 1110.2. All construction and operations activities are expected to occur on-site at biogas facilities. Therefore, the proposed project is not expected alter any conclusions in the NOP/IS for the Final EA that would create new solid or hazardous waste impacts.

Flaring biogas in lieu of complying with PAR 1110.2 was not analyzed in the 2007 Final EA. However, any flaring of biogas in lieu of complying with PAR 1110.2 would occur in existing biogas-fueled flares. Additional flare of biogas is not expected to generate any additional solid/hazardous waste. Flaring biogas in lieu of complying with PAR 1110.2 may result in the disposal of ICEs. However, the early disposal of ICEs was determined not to be significant in the 2007 Final EA. Therefore, no significant solid/hazardous waste impacts are expected, if operators choose to flaring biogas in lieu of complying with PAR 1110.2.

Based on the April 20, 2007 NOP/IS for the 2007 Final EA, implementing PAR 1110.2 not expected to hinder in any way any affected facility's ability to comply with existing federal, state, and local regulations related to solid and hazardous wastes. Consequently, it is anticipated that operators of affected facilities would continue to comply with federal, state, and local statutes and regulations related to solid and hazardous waste handling and disposal.

Based on these considerations, PAR 1110.2 is not expected to increase the volume of solid or hazardous wastes that cannot be handled by existing municipal or hazardous waste disposal facilities, or require additional waste disposal capacity other than already analyzed in the Final EA, which was determined to be less than significant for solid/hazardous waste. Further, implementing PAR 1110.2 is not expected to interfere with any affected facility's ability to comply with applicable local, state, or federal waste disposal regulations. Since no new significant or substantially worse solid/hazardous waste impacts were identified, no mitigation measures are necessary or required and an addendum is appropriate.

Traffic/Transportation

The NOP/IS for the 2007 Final EA concluded that traffic/transportation impacts would not be significant. PAR 1110.2 includes the same biogas NOx concentration limits for biogas-fueled ICEs that would have become effective July 1, 2012, if the technology review had been completed in 2010. The current proposal would extend the effective final NOx compliance dates that extend out to January 1, 2016 or January 1, 2018 under the alternative compliance option. PAR 1110.2 would only delay the installation and use of emissions control after treatment for stationary engines fired by biogas or replacement of ICEs in lieu of complying with PAR 1110.2. All construction and operations activities are expected to occur on-site at biogas facilities. Therefore, the proposed project is not expected alter any conclusions in the April 20, 2007 NOP/IS for the 2007 Final EA that the 2008 amendments to Rule 1110.2 would not create new traffic/transportation impacts.

As noted in the "Discussion" sections of other environmental topics, compliance with PAR 1110.2 is not expected to require construction activities or the installation of control equipment other than what was already evaluated in the NOP/IS. The NOP/IS estimated that 50 delivery and 75 worker trips per day would be required during construction, 76 ammonia trips would be required per quarter and 11 trips every three years would be required to replace catalyst. These values were updated in the 2007 Final EA in the section titled "Potential Environmental Impacts Found Not to Be Significant," based on the environmental analysis of construction air quality impacts. The construction air quality analysis in the 2007 Final EA concluded that a maximum of 62 new truck trips during construction would occur. Because the maximum number of truck trips during construction was less than the number of truck trips identified in the April 20, 2007 NOP/IS for the in the 2007 Final EA, the conclusion that transportation/traffic impacts would not to be significant is unchanged. The siting of each affected facility is expected to be consistent with surrounding land uses and traffic/circulation in the surrounding areas of the affected facilities. Similarly, the maximum number of truck trips during operation was updated as part of the air quality analysis. Alternative technologies in lieu of complying with PAR 1110.2 were estimated to need a maximum of 114 truck trips per day. Although this number is higher than what was discussed in the April 20, 2007 NOP/IS for the 2007 Final EA, it would not exceed any of the SCAQMD's transportation/traffic significance thresholds and, therefore, was concluded to be less than significant for transportation/traffic. Operation of PAR 1110.2 and existing Rule 1110.2 engines are expected to utilize similar number of employees, so no increase in employee trips are expected.

Flaring biogas in lieu of complying with PAR 1110.2 was not analyzed in the 2007 Final EA. However, any flaring of biogas in lieu of complying with PAR 1110.2 would occur at existing affected facilities using existing biogas-fueled flares. Therefore, no construction would be required. Affected operators that flare biogas in lieu of complying with PAR 1110.2 may remove biogas-fueled ICEs. PAR 1110.2 may result in the early removal of the biogas-fueled engines, but the impacts would be the same as removing them at a later date, which was evaluated in the April 27 NOP/IS 2007 Final EA and refined in the 2007 Final EA based on the air quality analysis.

Existing digester gas facilities have emergency standby generators that can be used to support the plant during emergencies, if the biogas-fueled engines are replaced by flares. Landfill gas facilities typically do not use emergency standby generators. The 2007 Final EA assumed that emergency engines would be installed at digester gas facilities that replaced their ICEs with alternative technologies in lieu of complying with the existing rule. If emergency engines are installed at an affected facility, the impacts would be no greater than those analyzed in the NOP/IS and 2007 Final EA. Therefore, no new impacts are expected to traffic/transportation from emergency standby generators. However, if new emergency standby generators are needed they are expected to be dropped in place on existing concrete surfaces within the boundaries of existing biogas facilities.

Since there would be no greater construction or change in operations that would affect traffic/transportation other than what was already evaluated in the NOP/IS and 2007 Final EA and determined to be less than significant for transportation/traffic, there would be no change to traffic/circulation. Therefore, PAR 1110.2 is not expected to conflict with an applicable plan, policy establishing measures of effectiveness for the performance of the circulatory system, applicable congestion management program, or conflict with adopted policies, plans or programs regarding public transit, bicycle or pedestrian facilities.

Though some of the facilities that would be affected by PAR 1110.2 may be located within an airport land use plan or, where such a plan has not been adopted, within two miles of a public airport or public use airport, any actions that would be taken to comply with the proposed project are not expected to influence or affect air traffic patterns or navigable air space based on the NOP/IS. Thus, PAR 1110.2 would not result in a change in air traffic patterns including an increase in traffic levels or a change in location that results in substantial safety risks.

The proposed project would not substantially change the way the affected engines would operate in relationship to transportation/traffic. Based on the analysis in the April 20 NOP/IS for the 2007 Final EA, the proposed project does not involve construction of any roadways or other transportation design features, so there would be no change to current roadway designs that could increase traffic hazards. Thus, the proposed project is not expected to substantially increase traffic hazards or create incompatible uses at or adjacent to the affected facilities.

Based on the analysis in the April NOP/IS for the 2007 Final EA, emergency access at each affected facility is not expected to be impacted by the proposed project. Further, each affected facility is expected to continue to maintain their existing emergency access gates. Since PAR 1110.2 does not involve any new construction activities not evaluated in the April NOP/IS for the 2007 Final EA and is not expected to alter operation of affected engines, the proposed project is not expected to increase hazards due to design features or alter emergency access.

Based upon these considerations, the proposed project would not substantially alter the significant adverse transportation/traffic impacts detailed in the April 20, 2007 NOP/IS for the 2007 Final EA or the 2007 Final EA, since significant or substantially worse transportation/traffic impacts are not expected from the implementation of PAR 1110.2; therefore, an addendum is appropriate. Since no significant or substantially worse transportation/traffic impacts were identified, no mitigation measures are necessary or required.

CONCLUSION

Analysis of the proposed project indicated that an Addendum the 2007 Final EA prepared pursuant to CEQA Guidelines §15164 is the appropriate CEQA document to analyze the potential adverse environmental impacts associated with PAR 1110.2 because SCAQMD staff has concluded that the proposed amendments result in some changes or additions to the 2007 Final EA; but that based on the analysis in this addendum, no new significant environmental effects or a substantial increase in the severity of previously identified significant effects were identified, thus none of the conditions described in CEQA Guidelines §15162 calling for preparation of a subsequent EIR have occurred:

1. No substantial changes are proposed in the project which required major revision of the previous EIR due to the involvement of new significant environmental effects or a substantial increase in the severity of previously identified significant effects; or
2. No substantial changes would occur with respect to the circumstances under which the project is undertaken which will require major revisions of the previous EIR due to the involvement of new significant environmental effects or a substantial increase in the severity of previously identified significant effects; or
3. No new information of substantial importance, which was not known and could not have been known with the exercise of reasonable diligence at the time the previous EIR was certified as complete shows any of the following:
   A. The project will have one or more significant effects not discussed in the previous EIR;
   B. Significant effects previously examined with be substantially more severe than shown in the previous EIR;
   C. Mitigation measures or alternatives previously found not to be feasible would be in fact feasible, and would substantially reduce one or more significant effects of the project, but the project proponents decline to adopt the migration measure or alternative; or
   D. Mitigation measures or alternatives which are considerably different from those analyzed in the previous EIR would substantially reduce one or more significant effects on the environment, but the project proponents decline to adopt the migration measure or alternative.

Based on the analysis in this addendum, PAR 1110.2 would not generate new significant environmental effects or a substantial increase in the severity of previously identified significant effects. Since PAR 1110.2 would not generate new significant environmental effects or as substantial increase in the severity of previously identified significant effects, no new mitigation measures or alternatives have been proposed. No changes to existing mitigation measures or alternatives are proposed. This conclusion is supported by substantial evidence provided as part of the environmental analysis in this Addendum as well as other documents in the record.

APPENDIX A

PROPOSED AMENDED RULE 1110.2

In order to save space and avoid repetition, please refer to the latest version of the PAR 1110.2 located elsewhere in the final rule package.

APPENDIX B

ASSUMPTIONS AND CALCULATIONS

Criteria Pollutant Emissions from Flares

Inputs/assumptions from the 2007 Final EA:
Total biogas use for the engines based on the 2008 survey is 4.45×10^{12} Btu or 4.45×10^{6} mmBtu.

Emission factors based on flare permit limits -

The average flare emission factor for NOx is 0.056 lb/mmBtu.

Emissions are:

249,200.00	lb/yr
682.74	lb/day

The average flare emission factor for VOC is 0.035 lb/mmBtu.

Emissions are:

155,750.00	lb/yr
426.71	lb/day

The average flare emission factor for CO is 0.115 lb/mmBtu.

Emissions are:

511,750.00	lb/yr
1,402.05	lb/day

ATTACHMENT J

SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT

Final Environmental Assessment:

Proposed Amended Rule 1110.2 – Emissions from Gaseous- and Liquid-Fueled Internal Combustion Engines (ICEs)

December 2007

SCAQMD No. 280307JK

Executive Officer
Barry R. Wallerstein, D. Env.

Deputy Executive Officer
Planning, Rule Development and Area Sources
Elaine Chang, DrPH

Assistant Deputy Executive Officer
Planning, Rules, and Area Sources
Laki Tisopulos, Ph.D., P.E.

Planning and Rules Manager
Planning, Rule Development and Area Sources
Susan Nakamura

Author:	James Koizumi	Air Quality Specialist
Technical Assistance:	Alfonso Baez, M.S,	Senior Air Quality Engineer
	Howard Lange, Ph.D.	Air Quality Engineer II
Reviewed By:	Steve Smith, Ph.D.	Program Supervisor, CEQA
	Martin Kay, P.E., M.S.,	Program Supervisor, Planning, Rules, and Area Sources
	Kurt Wiese	District Counsel
	Barbara Baird	Principal Deputy District Counsel

SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT
GOVERNING BOARD

CHAIRMAN: WILLIAM A. BURKE, Ed.D.
Speaker of the Assembly Appointee

VICE CHAIRMAN: S. ROY WILSON, Ed.D.
Supervisor, Fourth District
Riverside County Representative

MEMBERS:

MICHAEL D. ANTONOVICH
Supervisor, Fifth District
Los Angeles County Representative

BILL CAMPBELL
Supervisor, Third District
County of Orange

JANE W. CARNEY
Senate Rules Committee Appointee

RONALD O. LOVERIDGE
Mayor, City of Riverside
Cities Representative, Riverside County

JOSEPH K. LYOU, Ph.D.
Governor's Appointee

GARY OVITT
Supervisor, Fourth District
San Bernardino County Representative

JAN PERRY
Councilmember, Ninth District
Cities Representative, Los Angeles County, Western Region

MIGUEL A. PULIDO
Mayor, City of Santa Ana
Cities Representative, Orange County

TONIA REYES URANGA
Councilmember, City of Long Beach
Cities Representative, Los Angeles County, Eastern Region

DENNIS YATES
Mayor, Chino
Cities Representative, San Bernardino County

EXECUTIVE OFFICER:
BARRY R. WALLERSTEIN, D.Env.

PREFACE

The Draft Environmental Assessment (EA) for the Proposed Amended Rule 1110.2 – Emissions from Gaseous- and Liquid-Fueled Internal Combustion Engines (ICEs) was circulated for a 45-day public review and comment period from November 2, 2007 to December 18, 2007. One public comment letter was received and minor modifications were made to the Draft EA so it is now a Final EA. Deletions and additions to the text of the Draft EA are denoted using ~~strikethrough~~ and underlined, respectively. The primary changes to the proposed project since the release of the Draft EA are:

- The calculation of the monthly facility biogas use percentage may exclude natural gas fired during: any electrical outage at the facility; Stage 2 or higher electrical emergencies called by the California Independent System Operator Corporation; and when precipitation causes a sewage treatment plant to exceed its design capacity.
- The Executive Officer may approve the burning of more than ten percent natural gas in a land fill or digester gas-fired engine, when it is necessary, if the engine required more natural gas in order for waste heat recovery boiler to provide enough thermal energy to operate a sewage treatment plant, and other boilers at the facility are unable to provide the necessary thermal energy.
- The emission standards for CO and VOC for new electrical generation engines would be increased from 0.10 lb/MW-hr to 0.20 lb/MW-hr and 0.02 lb/MW-hr to 0.10 lb/MW-hr.
- An exception from the quarterly CO monitoring was added for diesel and other lean-burn engines that are subject or Regulation XX or have a NOx CEMs and that are not subject to a CO limit more stringent than 2000 ppm. The engines would still be subject to the I&M plans.

These changes were made in response to comments on PAR 1110.2. The first change was made to allow the operations of natural gas engine during emergencies. This would reduce allow the use of more natural gas combustion instead of diesel emergency engines during emergencies. As shown in the air quality analysis natural gas combustion generates less criteria and toxic air pollutants. Since emergency operations are not expected, they are considered speculative and therefore were not analyzed in the Final EA.

The second change would allow the use of more than ten percent natural gas used at sewage treatment plants where heat from ICEs is used for digesters, and when rainfall causes a sewage treatment plant to exceed its design capacity. During rainy weather, air quality is at its best and the impact of the higher emissions should be minimal. During the winter, the facility that uses heat from the ICEs for digesters may need additional natural gas to sustain digester operations. This exception was added since digester operations at sewage facilities are considered an essential operation. Affected sewage treatment plant operators are expected to add a condition to their permits to operate that specify the temperature at which this exception would apply. Emissions were estimated and evaluated in this Final EA. The additional emissions would not be significant neither would they be considered a substantial increase in the severity of an adverse environmental impact that would require recirculation.

The final change was made because manufacturers have stated that it is not technically possible for new electrical generation engines that require permits to meet the CARB 2007 Distributed Generation Emission Standards, which require emission equipment to large central power plants. However, the Engine Manufacturers Association commented that by increasing the proposed limits, in lbs/MW-hr, from 0.10 to 0.20 for CO and from 0.02 to 0.10 for VOC, some advanced engines may be able to comply. The choice of installing a new engine that complies with the CARB 2007 Distributed Generation Emission Standards and one that complies with the existing PAR 1110.2 with BACT is not expected to affect any environmental topic except for air quality. The revised CO and VOC limits, modified since the circulation of the Draft EA, would still achieve the same NOx reductions as the original proposal, and for an electrical generator without heat recovery, the revised limits will still achieve an 89 percent reduction of CO and a 77 percent reduction of VOC, compared to the current BACT limits for typical new engines. Therefore, altering the CO and VOC limits for new distributed generators is not expected to significantly adversely impact or substantially make any environmental topic found to be significantly adversely impacted in the Draft EA more severe.

These changes are expected to have similar affects on Alternatives B, C and D. Since Alterative A is the No Project Alternative, these changes would not affect it.

Pursuant to CEQA Guidelines §15088.5, recirculation is not necessary since the information provided does not result in new avoidable significant effects.

TABLE OF CONTENTS

TABLE OF CONTENTS (CONTINUED)

List of Tables

TABLE OF CONTENTS (CONTINUED)

Table 4-0a Summary of Exception for Natural Gas for Waste Heat Recovery Boilers

Table 4-0b Update to Proposed Project Emissions

TABLE OF CONTENTS (CONTINUED)

TABLE OF CONTENTS (CONTINUED)

TABLE OF CONTENTS (CONTINUED)

TABLE OF CONTENTS (CONCLUDED)

List of Figures

CHAPTER 1

EXECUTIVE SUMMARY

INTRODUCTION

The California Legislature created the South Coast Air Quality Management District (SCAQMD) in 1977[1] as the agency responsible for developing and enforcing air pollution control rules and regulations in the South Coast Air Basin (Basin) and portions of the Salton Sea Air Basin and Mojave Desert Air Basin referred to herein as the district. By statute, the SCAQMD is required to adopt an air quality management plan (AQMP) demonstrating compliance with all federal and state ambient air quality standards for the district[2]. Furthermore, the SCAQMD must adopt rules and regulations that carry out the AQMP[3]. The 2007 AQMP concluded that major reductions in emissions of volatile organic compounds (VOCs) and oxides of nitrogen (NOx) are necessary to attain the air quality standards for ozone and particulate matter (PM10 and PM2.5).

Rule 1110.2 was originally adopted in August 1990 to control NOx, carbon monoxide (CO), and VOC emissions from gaseous and liquid-fueled internal combustion engines (ICEs). For all stationary and portable engines over 50 brake horsepower (bhp), it required that either 1) NOx emissions be reduced over 90 percent, or; 2) the engines be permanently removed from service and/or replaced with electric motors. The rule was amended in September 1990 to make minor clarifications to the rule language. Rule 1110.2 was then amended again in August and December of 1994 to modify the CO monitoring requirements and to clarify rule language. The amendment of November 1997 eliminated the requirement for continuous monitoring of CO, reduced the source testing requirement from once every year to once every three years, and exempted nonroad engines, including portable engines, from most requirements. The last amendment in June 2005 made the previously exempt agricultural engines subject to the rule language.

The objective of proposed amended Rule (PAR) 1110.2 at this time is to further reduce NOx, VOC and CO emissions from gaseous and liquid-fueled ICEs. PAR 1110.2 would partially implement the 2007 AQMP Control Measure MCS-01 – Facility Modernization, which requires facilities to retrofit or replace their equipment to achieve emission levels equivalent to best available control technology (BACT). The proposed amendments would affect stationary, non-emergency engines and would increase monitoring requirements; reduce the emission standards equivalent to the current BACT; require new electrical generating engines to meet the same requirements as large central power plants; and clarify portable engine requirements. The proposed project would also remove obsolete portable engine requirements from the existing rule.

A Notice of Preparation and Initial Study (NOP/IS) (Appendix D), were prepared pursuant to the California Environmental Quality Act (CEQA). The NOP/IS identified environmental topics to be further analyzed in this document. The NOP/IS identified air quality, hazards and hazardous materials, and solid/hazard wastes as environmental topic areas that may be adversely affected by the proposed project. The NOP/IS was distributed to responsible agencies and interested parties for a 30-day review and comment period from April 26,

1 The Lewis-Presley Air Quality Management Act, 1976 Cal. Stats., ch 324 (codified at Health & Safety Code, §§40400-40540).
2 Health & Safety Code, §40460 (a).
3 Health & Safety Code, §40440 (a).

2007, to May 25, 2007. During that public comment period SCAQMD received two comment letters on the NOP/IS. Comments were received suggesting that the proposed project could also create significant adverse aesthetics and energy impacts. These environmental topic areas, therefore, are also analyzed in this EA. The comment letters and responses to comments are included in Appendix E.

This ~~Draft~~Final Environmental Assessment (EA), prepared pursuant to CEQA Guidelines §15252 and is a substitute document for an environmental impact report. This ~~Draft~~Final EA includes a comprehensive analysis of potential aesthetics, air quality, energy, hazards/hazardous materials, and solid/hazardous waste impacts as a result of implementing the proposed project. Although the NOP/IS only identified as potentially significant adverse air quality, hazards/hazardous materials, and solid/hazardous waste impacts for further analysis in the Draft EA, comments were received on the NOP/IS asserting that the proposed project could also generate potentially significant adverse aesthetics and energy impacts.

Subsequent to the release of the Draft EA changes were made to PAR 1110.2 in response to comments on the proposed amendments. The primary changes to the proposed project since the release of the Draft EA are:

- The calculation of the monthly facility biogas use percentage may exclude natural gas fired during: any electrical outage at the facility; Stage 2 or higher electrical emergencies called by the California Independent System Operator Corporation; and when precipitation causes a sewage treatment plant to exceed its design capacity.
- The Executive Officer may approve the burning of more than ten percent natural gas in a land fill or digester gas-fired engine, when it is necessary, if the engine required more natural gas in order for waste heat recovery boiler to provide enough thermal energy to operate a sewage treatment plant, and other boilers at the facility are unable to provide the necessary thermal energy.
- The emission standards for CO and VOC for new electrical generation engines would be increased from 0.10 lb/MW-hr to 0.20 lb/MW-hr and 0.02 lb/MW-hr to 0.10 lb/MW-hr.
- An exception from the quarterly CO monitoring was added for diesel and other lean-burn engines that are subject or Regulation XX or have a NOx CEMs and that are not subject to a CO limit more stringent than 2000 ppm. The engines would still be subject to the I&M plans

~~Any comments received during the public comment period on the analysis presented in this Draft EA will be responded to and included in the Final EA prior to making a decision on the proposed amended rule, the SCAQMD Governing Board must review and certify the EA as providing adequate information on the potential adverse environmental impacts of the proposed amended rule.~~ One comment letter was received from the public during the 45-day public comment period from November 2, 2007 to December 18, 2007. The comment letter and responses to comments are included in Appendix F of this Final EA.

Throughout this document, references to the proposed project or PAR 1110.2 are used interchangeably.

CALIFORNIA ENVIRONMENTAL QUALITY ACT

PAR 1110.2 is a "project" as defined by the California Environmental Quality Act (CEQA). CEQA requires that the potential adverse environmental impacts of proposed projects be evaluated and that methods to reduce or avoid identified significant adverse environmental impacts of these projects be implemented if feasible. The purpose of the CEQA process is to inform the SCAQMD's Governing Board, public agencies, and interested parties of potential adverse environmental impacts that could result from implementing the proposed project and to identify feasible mitigation measures when an impact is significant.

California Public Resources Code §21080.5 allows public agencies with regulatory programs to prepare a plan or other written documents in lieu of an environmental impact report once the Secretary of the Resources Agency has certified the regulatory program. The SCAQMD's regulatory program was certified by the Secretary of Resources Agency on March 1, 1989, and is codified as SCAQMD Rule 110. Pursuant to Rule 110 (the rule which implements the SCAQMD's certified regulatory program), SCAQMD has prepared this ~~Draft~~Final EA to evaluate potential adverse impacts from PAR 1110.2.

CEQA DOCUMENTATION FOR PROPOSED AMENDED RULE 1110.2

This ~~draft~~Final EA is a comprehensive environmental document that analyzes the environmental impacts from the currently proposed amendments to Rule 1110.2. SCAQMD rules, as ongoing regulatory programs, have the potential to be revised over time due to a variety of factors (e.g., regulatory decisions by other agencies, new data, lack of progress in advancing the effectiveness of control technologies to comply with requirements in technology forcing rules, etc.). The other documents which comprise the CEQA record for the currently proposed amendments to Rule 1110.2, include the NOP/IS of an EA for PAR 1110.2 (April 2007).

Notice of Preparation/Initial Study (NOP/IS) of an Environmental Assessment (EA) for the Proposed Amendments to Rule 1110.2, April 2007: The NOP/IS of an EA for the proposed amendments to Rule 1110.2 was released for a 30-day public review period from April 26, 2007, to May 25, 2007. The NOP/IS was released with an Initial Study, which contained a brief project description and the environmental checklist, as required by CEQA Guidelines. The environmental checklist contained a preliminary analysis of potential adverse environmental effects that may result from implementing the proposed amendments. The NOP/IS identified air quality, energy, hazards and hazardous materials, and solid/hazardous waste as the environmental topics that may be adversely affected by the proposed project. This NOP/IS is included in Appendix B of this ~~Draft~~Final EA.

PAST CEQA DOCUMENTATION FOR RULE 1110.2

Rule 1110.2, like other SCAQMD rules and regulations, comprises a regulatory program that changes over time due to advances in technology, regulatory requirements adopted by state and federal agencies, advances in technology not occurring as anticipated, etc. To reflect these changes, Rule 1110.2 has been amended a number of times since its original adoption in 1990. The following subsections describe the type of CEQA documents prepared for past amendments to Rule 1110.2 and summarize the modifications and analyses prepared for those documents. The current EA focuses on the currently proposed amendments to Rule 1110.2 and does not rely on the previously prepared CEQA documents described in the following subsections. The following documents can still be obtained by contacting the SCAQMD's Public Information Center at (909) 396-2309.

Final Environmental Assessment (EA) for Proposed Amended Rule 1110.2, June 2005 (SCAQMD No. 050318MK): A Draft EA for the proposed Rule 1110.2 was released for a 30-day public review period from March 18, 2005, to April 19, 2005. Proposed amendments to Rule 1101.2 included: removing exemption for all agricultural engines except emergency standby engines and engines powering orchard wind machines; adding more recordkeeping requirements; prohibiting use of portable engine generators to supply power to the grid or to a building, facility, stationary source or stationary equipment except in an emergency affecting grid stability; and removing outdated rule language. Rule 1110.1 was rescinded because it is superseded by the requirements of Rule 1110.2. After circulation of the Draft EA, a Final EA was prepared and certified by the SCAQMD Governing Board on June 3, 2005.

Final Subsequent Environmental Assessment for the Proposed Amended Rule 1110.2, November 14, 1997 (SCAQMD No. 970909DWS): Proposed amendments were made to address portable engine requirements under Rule 1110.2 and CARB's Statewide Portable Engine and Equipment Registration Regulation. Significant adverse impacts were identified and evaluated for air quality and energy. The Draft SEA was released for a 45-day public review and comment period from September 10, 1997 to October 28, 1997. No comments were received from the public.

Notice of Exemption (NOE) for the Proposed Amended Rule 1110.2, December 9, 1994: The proposed amendments clarified the meaning of the terms "originally installed" for purposes of determining compliance with the rule. A NOE was prepared for proposed amended Rule 1110.2, because the proposed amendments were administrative in nature and had no significant adverse impacts on the environment.

Notice of Exemption (NOE) for the Proposed Amended Rule 1110.2, August 12, 1994: The proposed amendments clarified the original intent that continuous in-stack CO monitoring system is not required if a continuous in-stack NOx monitoring system is not required. The proposed amendments harmonized Rule 1110.2 and RECLAIM.

Final Environmental Assessment (EA) for Proposed Rule 1110.2, September 7, 1990: The Governing Board requested that staff examine issues during the adoption hearing for Rule 1110.2 and provide recommendations Clarification of monitoring and periodic emission testing for engines over 1,000 bhp was added for NOx and CO emissions. A limited exemption was proposed for up-slope units at winter resort facilities that are operated less than 700 hours per year. Since the circumstances of the original project and the modifications were essentially the same, the Final EA for Proposed Rule 1110.2 was recertified for these changes.

Final Environmental Assessment (EA) for Proposed Rule 1110.2, August 3, 1990 (SCAQMD No. 900622ES): A Draft EA for the proposed rule was released for a 45-day public review period from May 25, 1990, to July 25, 1990. Four comment letters were received and responses were prepared. The EIR identified potential impacts and mitigation measures for water quality, risk of upset, transportation, energy, solid waste disposal, and human health. Significant adverse impacts were mitigated to less than significant. A mitigation monitoring plan was prepared.

INTENDED USES OF THIS DOCUMENT

In general, a CEQA document is an informational document that informs a public agency's decision-makers and the public generally of potentially significant adverse environmental effects of a project, identifies possible ways to avoid or minimize the significant effects, and describes reasonable alternatives to the project (CEQA Guidelines §15121). A public agency's decision-makers must consider the information in a CEQA document before making a decision on the project. Accordingly, this ~~Draft~~Final EA is intended to: (a) provide the SCAQMD Governing Board and the public with information on the environmental effects of the proposed project; and, (b) be used as a tool by the SCAQMD Governing Board to facilitate decision making on the proposed project.

Additionally, CEQA Guidelines §15124(d)(1) requires a public agency to identify the following specific types of intended uses of a CEQA document:

1. A list of the agencies that are expected to use the EA in their decision-making;
2. A list of permits and other approvals required to implement the project; and
3. A list of related environmental review and consultation requirements required by federal, state, or local laws, regulations, or policies.

To the extent that local public agencies, such as cities, county planning commissions, et cetera, are responsible for making land use and planning decisions related to projects that must comply with the requirements in PAR 1110.2, they could possibly rely on this EA during their decision-making process. Similarly, other single purpose public agencies approving projects at facilities complying with PAR 1110.2 may rely on this EA.

AREAS OF CONTROVERSY

During the public comment period for the NOP/IS and at public meetings held for PAR 1110.2, commentators expressed concerns about several issues. The expense of installing monitoring and emissions control equipment would cause facility operators to replace existing ICEs with alternative technology. Depending on the alternative technology used, it was asserted that PAR 1110.2 could lead to: increased emissions from certain compliance options; eliminating renewable energy sources if operators replace landfill or digester (biogas) ICEs with flares; replacing pumps with electric motors and emergency diesel generators, thus, creating adverse impacts to public services. Commenters stated that limited supplies of diesel fuel could lead to adverse public service impacts if emergencies last for an extended period of time, such as a loss of water when responding to major fire emergencies.

In response to public comments, SCAQMD staff added low-use exceptions from monitoring and future BACT limits, increased the combined horsepower threshold for CEMS to 1,500 horsepower and added several other exceptions which will significantly reduce the number of required CEMS. SCAQMD staff has also committed to conduct a technology assessment in 2010 to evaluate whether or not cost-effective control technologies are available to allow compliance by biogas engines with the final emission compliance limits in the proposed amended rule, avoid the need for biogas flaring, and eliminate or minimize potential adverse impacts identified by the regulated industry. If the assessment shows a potential for replacing ICEs with continuous flaring or that cost-effective control technology is not available for biogas engines, staff will return to the Governing Board with a proposal to address any new significant adverse impacts. Based on these adjustments, SCAQMD staff believes that many of the controversial aspects of PAR 1110.2 for biogas and non-biogas facilities can be addressed.

SCAQMD staff asserts that if water agencies choose to replace ICEs with electric motors as a compliance option, it would be more efficient and less costly to use existing natural gas engines as emergency backup equipment than buying new diesel ICEs. Therefore, SCAQMD staff believes that using existing natural gas engines as emergency generators for electric motors would prevent widespread shortages of diesel fuel for emergency backup generators in the event of an extended emergency.

Comments were also received that the NOP/IS only addressed SCR as compliance option for emission control for biogas engines. In response to these comments this EA also evaluates potential adverse secondary environmental impacts from SCR, NOxTech, CL.Air ®, boilers, gas turbines, microturbines, fuel cells, and biogas-to-LNG facilities as potential compliance options.

Commenters were concerned that if multiple engines used biogas that not all engines would be able to run with 10 percent or less natural gas resulting in more flaring of biogas. SCAQMD staff has added an exception that would allow the use of more than 10 percent natural gas if it reduces flaring.

Commenters have expressed concerns about the distributed power emission standards. PAR 1110.2 would implement Senate Bill (SB) 1298 distributed generation emission standards for new electrical generating engines, which was adopted by the California state legislature in 2000. SB 1298 also established a goal to have local districts require permitted distributed generation (DG) equipment to meet BACT levels by the earliest practicable date. These standards have been in effect since January 1, 2007 for DG equipment that does not require a SCAQMD permit.

EXECUTIVE SUMMARY

CEQA Guidelines §15123 requires a CEQA document to include a brief summary of the proposed actions and their consequences. In addition, areas of controversy including issues raised by the public must also be included in the executive summary. This ~~Draft~~Final EA consists of the following chapters: Chapter 1 – Executive Summary; Chapter 2 – Project Description; Chapter 3 – Existing Setting, Chapter 4 – Potential Environmental Impacts and

Mitigation Measures; Chapter 5 – Project Alternatives; Chapter 6 - Other CEQA Topics and various appendices. The following subsections briefly summarize the contents of each chapter.

Summary of Chapter 1 – Executive Summary

Chapter 1 includes a discussion of the legislative authority that allows the SCAQMD to amend and adopt air pollution control rules, identifies general CEQA requirements and the intended uses of this CEQA document, areas of controversy and summarizes the remaining five chapters that comprise this ~~Draft~~Final EA.

Summary of Chapter 2 - Project Description

The objective of the project is to partially implement 2007 AQMP Control Measure MSC–01 – Facility Modernization, which requires facilities not participating in the NOx Regional CLean Air Incentives Market (RECLAIM) Program to retrofit to current BACT or replace existing equipment with equipment that meets current BACT requirements at the end of a predetermined life span. PAR 1110.2 would also increase rule compliance by better monitoring, recordkeeping and reporting. PAR 1110.2 would implement Senate Bill (SB) 1298 distributed generation emission standards for new electrical generating engines and, address issues raised by EPA with the current Rule 1110.2.

Summary of Chapter 3 - Existing Setting

Pursuant to the CEQA Guidelines §15125, Chapter 3 – Existing Setting, includes descriptions of those environmental areas that could be adversely affected by PAR 1110.2 as identified in the Initial Study (Appendix D). The following subsections briefly highlight the existing setting for aesthetics, air quality, energy, hazards/hazardous materials, and solid/hazardous waste, which were the only environmental areas identified that could potentially be adversely affected by implementing PAR 1110.2.

Aesthetics

ICEs are used for commercial and industrial applications. ICEs can be housed within buildings or placed outside. Depending on the placement of buildings and the size of the facility, the existing ICE system may or may not be visible from outside the property line.

Air Quality

SCAQMD staff conducted a survey in 2005 of non-agricultural, stationary, non-emergency engines. A total of 580 facilities were contacted, and 313 of those facilities responded (54 percent facility response rate). The survey collected data for 631 out of a total of 859 active engines (73.5 percent response rate based on number of engines). The resulting calculated total emissions for all survey engines were scaled up by category to account for the 76.3 percent representation rate.

A program of unannounced compliance testing conducted by SCAQMD's compliance department revealed that, although engines can generally meet emission limits when emission control systems are properly maintained and adjusted as is generally the case at the time of source testing; emissions during normal operation frequently exceed the emission limits. The resulting total calculated excess emissions for all stationary, non-emergency engines in the district are 9,195 pounds of NOx per day, 2,517 pounds of VOC per day and 54,243 pounds of CO per day.

Energy

The combined annual electricity production in Los Angeles, Orange, Riverside and San Bernardino County is 106,311 gigawatt-hours (gW-hours). The natural gas demand for California is approximately 5,732 million cubic feet per day. In 2001, refineries in California processed approximately 655 million barrels of crude oil.

California's Renewable Portfolio Standard (RPS) was developed under Senate Bills 1038, 1078, 1250 and 107. The senate bills require retail seller of electricity to increase the amount of renewable energy they procure by one percent each year until 20 percent of total retail sales are served with renewable energy by 2017.

The Energy Commission's 2003 Integrated Energy Policy Report recommended accelerating that goal to 2010, and the 2004 Energy Report Update further recommended increasing the target to 33 percent by 2020. The state's Energy Action Plan supported this goal. The PUC accelerated the RPS goal, requiring the utilities to obtain 20 percent of their power from renewables sources by 2010 (Senate Bill 107 codified this goal in state law).

On April 25, 2006, Governor Schwarzenegger signed Executive Order S-06-06. The Executive Order established targets for the production and use of biofuels and biopower, and directed state agencies with important biomass connections to work together to advance biomass programs in California, while providing environmental protection and mitigation. The Executive Order S-06-06 targets 20 percent biofuel by 2010, 40 percent by 2020 and 75 by 2050. Governor Schwarzenegger targeted biomass to contribute 20 percent of the 20 percent goal for renewable electricity generated under RPS for the 2010 and the 33 percent goal for 2020.

Hazards and Hazardous Materials

The use, storage and transport of hazardous materials are subject to numerous laws and regulations at all levels of government. The most relevant existing hazardous materials laws and regulations include hazardous materials management planning, hazardous materials transportation, hazardous materials worker safety requirements, hazardous waste handling requirements and emergency response to hazardous materials and waste incidents. Potential risk of upset is a factor in the production, use, storage and transportation of hazardous materials. Risks of upset concerns are related to the risks of explosions or the release of hazardous substances in the event of an accident or upset conditions.

Solid/Hazardous Waste

Landfills are permitted by the local enforcement agencies with concurrence from the California Integrated Waste Management Board (CIWMB). Local agencies establish the maximum amount of solid waste which can be received by a landfill each day and the operational life of a landfill. Based on a search of the California Integrated Waste Management Board's Solid Waste Information System (SWIS) on May 16, 2007, there are approximately 750,846,000 cubic yards (1,250,367,507 tons) of remaining capacity at Class

II and III facilities in Los Angeles, Orange County, Riverside and San Bernardino that accept construction waste. There are three Class I landfills in California: Chemical Waste Management Kettleman Hills in Kettleman City, CA; Clean Harbors Buttonwillow in Buttonwillow, CA, and Clean Harbors Westmorland in Westemorland, CA. Chemical Waste Management Kettleman Hills has a remaining capacity of 7,360,000 cubic yards with an estimated closure date of 2037. Clean Harbors Buttonwillow and Westmorland have a remaining capacity of 12,731,000 cubic yards with an estimated closure date of 2036.

Summary of Chapter 4 - Environmental Impacts

CEQA Guidelines §15126(a) requires that a CEQA document, "shall identify and focus on the significant environmental effects of the proposed project. Direct and indirect significant effects of the project on the environment shall be clearly identified and described, giving due consideration to both the short-term and long-term effects."

The following subsections briefly summarize the analysis of potential adverse environmental impacts from the adoption and implementation of PAR 1110.2.

Aesthetics

In the NOP, SCAQMD staff stated that PAR 1110.2 would not require any new development, but may require minor modifications to building or other structures for retrofit or replacement. The NOP/IS concluded that modified or replacement equipment would not be substantially difference in physical appearance than the other existing commercial or industrial equipment at these facilities. It was concluded that retrofitted, replaced and/or new equipment would not obstruct scenic resources or degrade the existing visual character of a site, including but not limited to: trees, rock outcroppings, or historical buildings.

Subsequent to the release of the NOP, some biogas facilities stated they may choose to replace ICEs with biogas-to-LNG facilities, gas turbines, microturbines, boilers, or flares. A technology assessment will be completed in 2010 to verify that feasible control options are available to comply with PAR 1110.2 to prevent replacing biogas ICEs with continuous biogas flaring. If the technology assessment shows potential for flaring or that feasible control options for biogas engines are not available, staff will return to the Governing Board with a proposal to address any new significant adverse impacts, including rule changes if needed.

Biogas facility operators may choose to replace existing ICEs with biogas-to-LNG facilities, gas turbines, microturbines or boilers. Turbines, microturbines and boilers are similar in physical characteristics to ICE systems. It is unlikely that replacing ICEs with one of these technologies would modify the visual characteristics of the existing facilities. Because of the size of the biogas-to-LNG facilities, process equipment and truck loading racks, the equipment and truck loading operations may be visible from outside of the facility. In addition, the process equipment may need additional lighting. Therefore, the installation of a biogas-to-LNG facility may significantly alter the aesthetics of an existing facility.

Air Quality

PAR 1110.2 would require the installation and operation of CEMs systems, air to fuel ratio controllers, CO analyzers, replacement of three way catalyst or installation of oxidation catalyst on non-biogas ICEs. Facility operators of biogas ICEs are expected to install retrofit emission control technology, such as oxidation catalyst and SCR or NOxTech systems. However, commenters have stated that the cost of SCR systems may make it more economical to remove the existing biogas ICEs and replace them with an alternative technology (boilers, gas turbines, microturbines, fuel cells, and biogas-to-LNG plants).

Commenters have stated that the cost of monitoring and control technology would make replacing biogas ICEs with LNG facilities, gas turbines, microturbines, boilers, or flares more economical. These alternative technologies could result in increases in some emissions. SCAQMD staff has committed to conduct a technology review in 2010 to verify that feasible control options for biogas engines are available and that ICEs would not be replaced with continuous flaring. If the technology assessment shows the potential for flaring, staff will return to the Governing Board with a proposal addressing any new significant adverse impacts, including rule changes if needed. Therefore, the replacement of ICEs with flares is not analyzed in this report.

Based on cost estimates it was determined that replacing certain non-biogas engines with electric motors would have cost savings over installing emission controls, monitoring and complying with inspection and maintenance (I & M) requirements. SCAQMD staff estimated that 75 percent of the operators with engines that have cost savings would voluntarily replace ICEs with electric motors. The technology assessment in 2010 will evaluate the number of existing ICEs that are voluntarily replaced with electric motors. Emissions from control technology (ammonia slip from SCR) or ICE replacement technology (gas turbines, biogas to liquefied natural gas facilities, etc.), and secondary emissions from delivery or haul trucks, and emergency engines were estimated and evaluated.

Criteria Pollutants

Construction and operational emissions would occur concurrently; therefore, the emissions from both were added together. The resulting emissions were compared to SCAQMD operational criteria pollutant thresholds. The worst-case criteria emissions would occur if all biogas facility operators chose to replace ICEs with gas turbines. In this scenario, PAR 1110.2 would reduce 4,311 pounds of NOx per day, 46,868 pounds of CO per day, 1,995 pounds of VOC per day and 13 pounds of SOx per day. PM10 would increase by 142 pounds per day and PM2.5 would increase by 142 pounds per day. The PM10 increase would be below the significance threshold of 150 pounds per day. The PM2.5 emissions would be greater than the significance threshold of 55 pounds per day. Therefore, PAR 1110.2 would be significant for PM2.5 operational emissions.

Air Toxic Pollutants

Health risk is evaluated on a localized level by evaluating the adverse impacts of a facility on the near-by community. Health risks were estimated from the largest aqueous ammonia emissions associated with SCR at an affected facility, the largest diesel exhaust emissions from diesel emergency generators, and the largest amount of delivery trucks at an affected facility.

Only one of these scenarios would not typically occur at a single facility, since it was believed that biogas facility operators would install the same type of add-on control or ICE alternative technology for all biogas engines at a given facility. Therefore, biogas operators would either install SCR (ammonia), a biogas-to-LNG plant (diesel particulate from LNG trucks) or ICE alternative technology that would require an emergency generator (gas turbines or microturbines). However, some facilities have both non-biogas and biogas engines at the same facility. It is possible that a biogas facility would have emergency engines for both non-biogas electric motors and either SCR, a biogas-to-LNG plant or emergency generators for biogas ICE alternative technology.

The carcinogenic health risk from the facility with the largest number of diesel truck trips would be two in one billion (2.0×10^{-9}), which is less than the significant threshold of ten in one million (1.0×10^{-5}). The carcinogenic health risk from diesel emergencies generators at the largest biogas facility would be 3.4 in one million (3.4×10^{-6}), which is less than the significant threshold of ten in a million. The carcinogenic health risk from the facility with the largest non-biogas emergency engine would be 18 in one million (1.8×10^{-5}), which is greater than the significance threshold of 10 in a million. Therefore, PAR 1110.2 would be significant for carcinogenic health risk from diesel particulate emissions.

Diesel particulate filters have been certified as at least 85 percent efficient for stationary diesel engines. This control efficiency would be enough to reduce the health risk to below the significance threshold of 10 in one million even if the greatest carcinogenic health risk from both the biogas and non-biogas emergency engines at single facilities were added together (3.4 in one million + 18 in one million = 21.4 in one million x (1 – 0.85) = 3.2 in one million). Therefore, diesel particulate filters would mitigate carcinogenic health risk from PAR 1110.2 to not significant.

The chronic non-carcinogenic hazard indices from diesel particulate matter at LNG facilities or facilities with emergency generators would be less than the significance threshold of 1.0. The chronic and acute hazard indices from ammonia slip at the largest facility would be less than the significance threshold of 1.0.

Global Warming

Combustion processes generate greenhouse gas (GHG) emissions in addition to criteria pollutants. The GHG analysis focused on directly emitted CO2 because this is the primary GHG pollutant emitted during the combustion process and is the GHG pollutant for which emission factors are most readily available. Since the half-life of CO2 is approximately 100 years, for example, the effects of GHGs are longer-term, affecting global climate over a relatively long time frame. As a result, the SCAQMD current position is to evaluate GHG effects over a longer timeframe than a single day.

SCAQMD staff estimated that replacing certain non-biogas engines with electric motors would generate less cost than complying with the requirements of PAR 1110.2. SCAQMD staff estimated that approximately 25 percent of these 225 engines with cost savings may not be replaced because of reasons other than cost. Therefore, 169 engines were assumed to be voluntarily replaced in the air quality analysis. As a worst-case (gas turbine biogas compliance option) it was estimated that at least 15 non-biogas engines would need to be replaced with electric motors to achieve overall CO2 reductions from PAR 1110.2. It is possible that fewer than 169 non-biogas engines could be replaced with electric motors, but, given the lower costs of installing and operating electric motors, it is likely that at least 15 non-biogas engines or more would be replaced with electric motors.

Energy

Total Energy Impacts

Under the worst-case energy scenario (replacing digester gas engines with microturbines and landfill gas engines with LNG plants), PAR 1110.2 would reduce natural gas used by at least 181,719 MMBtu per year, which includes the voluntary replacement of existing non-biogas engines with electric motors where it costs less than complying with PAR 1110.2. The total electricity production loss by the worst-case biogas scenario (replacing digester gas engines with microturbines and landfill gas engines with LNG plants) would be 576,527 MW-hours per year which is less than one percent of 120,194 GW-hours per year available in Southern California. The maximum amount of diesel used in worst-case construction and operations would be 1,871 gallons of diesel per day, which is less than one percent of the 10 million gallons consumed per day in California, and therefore is less than significant.

Renewable Energy Impacts

A technical assessment will be completed in 2010, which will verify that PAR 1110.2 would not cause biogas facility operators to replace existing ICEs with continuous flaring. If the technology assessment shows potential for flaring or that feasible control options for biogas engines are not available, staff will return to the Governing Board with a proposal to address any new significant adverse impacts. Because of the technology assessment under PAR 1110.2, SCAQMD staff believes that facilities operators will either use add-on control or replace ICEs with alternative technologies that would either generate electricity or LNG; there would be only adverse impacts to renewable energy supplies from efficiency losses between the existing ICEs and the ICEs with add-on control or ICE replacement technologies. The largest electrical loss from renewable energy sources because of differences in efficiency between alternative technologies and the existing ICEs would be 101,013 MW-hours per year for the microturbines compliance option.

There may be adverse energy impacts in an individual government program, but any energy losses other than from efficiency losses from one program may be made up in another program. For example, if a landfill gas facility operator chooses to replace an existing biogas ICEs with a LNG facility, not only would there be a loss of electricity generation, but the LNG facility would need energy from the grid to operate. However, the landfill gas would not be wasted, but treated and sold as LNG, which is a renewable fuel. Therefore, while this might affect the California's Renewables Portfolio Standard (RPS), which focuses only on electricity, it would assist renewable fuel/biomass goals under Governor Schwarzenegger's Executive Order S-06-06.

<u>Hazards and Hazardous Materials</u>

<u>Ammonia Impacts</u>

SCR systems require either urea or ammonia. Urea would not result in offsite adverse impacts. The Executive Officer has prohibited the permitting of control technology using anhydrous ammonia. To further reduce hazards associated with ammonia, a permit condition that limits the aqueous ammonia concentration to 19 percent is typically required. Since 20 percent aqueous ammonia is evaluated by CalARP, adverse impacts from aqueous ammonia were evaluated based on the 20 percent aqueous ammonia in this document. The NOP/IS determined that adverse impacts from transport of aqueous ammonia would be less than significant. No comments were received on this analysis so no further evaluation was completed in this document. SCAQMD staff estimated that the largest aqueous ammonia tank would be 5,000 gallons. The toxic endpoint for a 5,000 gallon aqueous ammonia tank would be 0.1 miles. Based on a survey of biogas facilities, some facilities have receptors with 0.1 miles of the existing ICEs. Since it is assumed that aqueous ammonia tanks for SCR system would need to be relatively near to the existing ICEs, it is assumed that the toxic endpoint for aqueous ammonia from a catastrophic failure of the storage tank would significantly adversely affect the receptors within 0.1 miles of the ICEs. Therefore, PAR 1110.2 is significant for aqueous ammonia accidental release.

<u>Liquefied Natural Gas Impacts</u>

Biogas to LNG plants would include LNG storage tanks. Based on the facility survey and design of the LNG facility at the Bowerman Landfill, the largest LNG tank would be 71,000 gallons. The overpressure from a catastrophic release of 71,000 gallons of LNG with a berm was estimated to be 0.2 mile. Based on a survey of biogas facilities, some facilities have receptors with 0.1 miles of the existing ICEs. Therefore, PAR 1110.2 is significant for LNG storage tank accidental release.

Four accidental release scenarios were identified for the transport of LNG: release of LNG into a pool that evaporates and disperses without ignition; the ignition of a flammable cloud, a boiling liquid expanding vapor explosion (BLEVE) occurs, or the tank ruptures, rockets away and ignites. The worst-case endpoint from these scenarios is 0.3 miles from a vapor cloud fire, BLEVE or where rocketing tank would land. Assuming that these accidents would occur near receptors, PAR 1110.2 is significant for LNG accidental release during transport.

The toxic endpoints and overpressures from facilities within a quarter mile of a schools or two miles of an airport or air field would not reach the schools, airport or air field.

<u>Solid/Hazardous Waste</u>

The NOP/IS stated that solid/hazardous waste might be significantly adversely impacted by PAR 1110.2. Adverse solid/hazardous waste impacts are associated with the replacement of ICEs and the disposal of catalysts. The replacement of ICEs would occur once during construction. The replacement of catalyst would occur both during construction and operation. An analysis was completed that compared the capacities of existing solid and hazardous waste landfills and it was determined that the adverse solid/hazardous waste impacts associated with PAR 1110.2 would not be significant.

Potential Environmental Impacts Found Not To Be Significant

The Initial Study for PAR 1110.2 includes an environmental checklist of approximately 17 environmental topics to be evaluated for potential adverse impacts from a proposed project. Review of the proposed project at the NOP/IS stage identified air quality, energy, hazards/hazardous material and solid/hazardous waste for further review in the Draft EA. The Initial Study concluded that the project would have no significant direct or indirect adverse effects on the remaining environmental topics. During that public comment period, SCAQMD received two comment letter on the NOP/IS; however, no comments were received on the NOP/IS or at the public meetings that changed this conclusion. The comment letters and its response are included in Appendix E. However, during the analysis for the Draft EA, SCAQMD staff determined that aesthetics may be significantly adversely impacted by PAR 1110.2. The screening analysis concluded that the following environmental areas would not be significantly adversely affected by PAR 1110.2:

- agriculture resources
- biological resources
- cultural resources
- geology/soils
- hydrology and water quality
- land use and planning
- mineral resources
- noise
- population and housing
- public services
- recreation
- transportation/traffic

Consistency

The Southern California Association of Governments (SCAG) and the SCAQMD have developed, with input from representatives of local government, the industry community, public health agencies, the United States Environmental Protection Agency (USEPA) - Region IX and the California Air Resources Board (CARB), guidance on how to assess consistency within the existing general development planning process in the Basin. Pursuant to the development and adoption of its Regional Comprehensive Plan Guide (RCPG), SCAG has developed an Intergovernmental Review Procedures Handbook (June 1, 1995). The SCAQMD also adopted criteria for assessing consistency with regional plans and the AQMP in its CEQA Air Quality Handbook. Analysis of the proposed project shows that it is consistent with the RCPG.

Summary Chapter 5 - Alternatives

Four feasible alternatives to the proposed amended rule are summarized in Table 1-1: Alternative A (No Project), Alternative B (Low-Use Alternative), Alternative C (Compliance Only Alternative) and Alternative D (BACT). A comparison of the potential aesthetic and air quality adverse impacts from each of the project alternatives with PAR

1110.2 is given in Table 1-2. No other significant adverse impacts were identified for PAR 1110.2 or any of the project alternatives. The proposed project is significant for air quality from NOx emission during construction activities; for energy from total and renewable resource electricity adverse impacts, and for hazards/hazardous materials from accidental releases from aqueous ammonia storage and LNG transport and storage.

Alternative A (No Project Alternative)

Since Alternative A is the same as the existing setting, no significant construction emission impacts are expected. There would be no construction, so there would be no construction emissions. One of the primary reasons for amending Rule 1110.2 is to improve compliance with the emission concentrations of the rule by imposing CEMs requirements, inspection and monitoring plan requirements; monitoring, testing, recordkeeping, and reporting requirements; etc. By not amending Rule 1110.2, it is possible that a large number of affected engines would continue to operate out of compliance. NOx, CO and VOC emissions (9,195 lbs of NOx per day, 54,243 pounds of CO per day and 2,517 pounds of VOC per day) would exceed the significance criteria of 55 pounds per day of NOx, 550 pounds per day of CO and 55 pounds per day of VOC. Engines exceeding compliance limits could do so in amounts that exceed applicable SCAQMD significance thresholds. There would be no change in ICE operation so there would be no adverse energy impacts. There would be no change in control or operational equipment so there would be no new aqueous ammonia storage or LNG transport and storage. Because NOx, CO and VOC would be significant for Alternative A, it would not accomplish a major objective of the proposed project which is to further reduce NOx, CO and VOC emissions from ICEs. Since Alternative A does not implement the objective, the proposed project is preferred over Alternative A.

Alternative B (Low Use Alternative)

Alternative B would increase the low-use exception to concentration limits and extend the 15 minute averaging time for compliance limits to one hour. In PAR 1110.2, the low-use exception applies to ICEs that are used less than 500 hours per year or burn less than 1,000 MMBtu per year. Alternative B would increase the low-use exception to 1,000 hours or 2,000 MMBtu per year. Alternative B would include an exception for lean-burn engines from the CEMS requirement. These changes would require less new monitoring and control technology for low-use ICEs and for engines that can meet the compliance limit concentrations, but have fluctuations in concentrations. Alternative B also assumes that 169 non-biogas engines would be replaced by electric motors because there would be a cost savings over complying with PAR 1110.2. While there would be less new control technology installed overall, facility operators who need to install equipment, may still install that equipment at the same rate as proposed in PAR 1110.2. Operational emissions from Alternative B may be greater than PAR 1110.2 because less monitoring and emission controls are added. Therefore, to be conservative it is assumed that the adverse construction impacts from Alternative B would be similar to PAR 1110.2. Aesthetic, energy and hazards/hazardous material adverse impact are expected to be similar to PAR 1110.2 and therefore, significant. PAR 1110.2 would be preferred to Alternative B, because it would reduce more NOx, CO and VOC emissions, while still providing a low-use exemption.

Alternative C (Compliance Only Alternative)

Alternative C would keep the concentration compliance limits the same as the existing Rule 1110.2, but would add compliance requirements. It was assumed that no facilities would voluntarily replace existing ICEs with electric motors under Alternative C. Additional infrastructure and monitoring is not expected to change the visual character of the facility or surroundings, therefore, aesthetics would not be significant. Additional compliance requirements would not generate significant adverse construction or operational air quality impacts. Adverse energy impacts from monitoring equipment and travel associated with additional source test are expected to be minor; therefore, less than significant. Alternative C would have no significant hazards/hazardous material impacts, because hazards would not be generated from increased monitoring and source testing. Alternative C would not generate significant solid or hazardous waste from monitoring or source testing. Therefore, Alternative C would not be significant for any environmental topic. Alternative C would not generate any significant environmental impacts, but would not achieve as much emission reductions nor would Alternative C include the project objective of partly implement 2007 AQMP Control Measure MCS-01 – Facility Modernization.

Alternative D (BACT Alternative)

Alternative D, BACT Alternative, would lower compliance limits to BACT levels (11 ppm for NOx, 30 ppm for VOC and 70 ppm for CO). The compliance dates for the compliance limits were expanded from 2012 to 2014 for biogas engines as a natural life allowance. Alternative D would have adverse environmental impact similar to PAR 1110.2. Alternative D may exacerbate the adverse environmental impacts because larger or additional control may be required to meet the lower CO compliance concentration limits. Alternative D does include the same low-usage exemption as the proposed project. Alternative D would include a mandatory replacement of non-biogas engines for categories where there would be a cost savings over complying with PAR 1110.2. Alternative D would include an exception for facility operators that can demonstrate to the Executive Officer that other considerations would prevent the replacement of the existing ICEs with electric motors where there would be a cost savings over complying with PAR 1110.2. While in practice Alternative D would have greater adverse environmental impacts, the assumptions applied to PAR 1110.2 would also apply to Alternative D. Therefore, for this analysis the adverse environmental impacts from PAR 1110.2 and Alternative D would be similar. Alternative D would be significant for aesthetics, air quality, energy, and hazards/hazardous waste. PAR 1110.2 would be preferable to Alternative D, because the actual adverse impacts from PAR 1110.2 would be less than Alternative D. PAR 1110.2 includes lower CO compliance concentrations and low-use exception, which industry has requested based on cost effectiveness.

Since Alternatives A and C would not achieve proposed project objectives, the proposed project is preferred to Alternatives A and C. Since the proposed project would qualitatively be better than Alternative B, the proposed project is preferred to Alternative B. The proposed project is preferred to Alterative D, because it contains the low-use exception and higher CO compliance concentration limits, which industry has requested based on cost effectiveness. Therefore, the proposed project is preferred over the project alternatives.

Summary Chapter 6 - Other CEQA Topics

CEQA documents are required to address the potential for irreversible environmental changes, growth-inducing impacts and inconsistencies with regional plans. Consistent with the 2007 AQMP EIR, additional analysis of the proposed project confirms that it would not result in irreversible environmental changes or the irretrievable commitment of resources, foster economic or population growth or the construction of additional housing, or be inconsistent with regional plans.

Table 1-1
Summary of PAR 1110.2 and Project Alternatives

Requirement	**Proposed Project**	**Alternative A (No Project)**	**Alternative B (Low Use)**	**Alternative C (~~Compliance Only~~ Enhanced Compliance)**	**Alterative D (BACT)**
Compliance Limits	11 ppm NOx 30 ppm VOC 250 ppm CO	NOx VOC CO (ppm) Table I: 11 30 70 Table II: 36 250 2,000 Table III ≥ 50 bhp: 36 250 NA Table III >50 bhp < 500 bhp: 45 250 NA	11 ppm NOx 30 ppm VOC 250 ppm CO	NOx VOC CO (ppm) Table I: 11 30 70 Table II: 36 250 2,000 Table III ≥ 50 bhp: 36 250 NA Table III >50 bhp < 500 bhp: 45 250 NA	11 ppm NOx 30 ppm VOC 70 ppm CO
Efficiency Correction for Biogas	No	Yes	No	No	No
Averaging Times	15 min	15 min	1 hour	15 min	15 min
Compliance Dates	Emission limits 2010 - 2012 Monitoring 2008 - 2010	N/A	Emission limits 2010 - 2012 Monitoring 2008 - 2010	Monitoring 2008 - 2010	Emission limits 2012 - 2014 Monitoring 2008 - 2010
Natural Life Allowance	None	N/A	None	None	Additional two years to comply with concentration limits
Natural Gas Percentage Limits	10	N/A	10	25	10
Low Usage Exception from Non-Biogas Compliance Limits	Less than 500 hours or less than 1,000 MMBtu annually	None	Less than 1,000 hours or less than 2,000 MMBtu annually	None	Same as PAR 1110.2
CEMS	Stationary ICE groups of 1,500 bhp ICEs or more included in CEMS unless < 500 bhp or operated <1,000 hr/yr or < 8 x 10^9 Btu/year	N/A	Same as PAR 11102, except lean-burn engines are exempt from CEMS requirements	Same as PAR 1110.2	Same as PAR 1110.2

Table 1-1 (concluded)
Summary of PAR 1110.2 and Project Alternatives

Requirement	Proposed Project	Alternative A (No Project)	Alternative B (Low Use)	Alternative C (~~Compliance Only~~ Enhanced Compliance)	Alterative D (BACT)
Replacement of Existing ICE with Electric Motors	Voluntary	None	Voluntary	None	Mandatory

Table 1-2
Comparison of Adverse Environmental Impacts of the Alternatives

Environmental Topic	Proposed Project	Alternative A (No Project)	Alternative B (Low Use)	Alternative C (~~Compliance Only~~ Enhanced Compliance)	Alterative D (BACT)
Aesthetics	Significant	Not significant no Impact	Significant less than PAR 1110.2	Not significant	Significant Equivalent to PAR 1110.2
Air Quality					
Criteria	Significant	Significant, greater than PAR 1110.2	Significant Equivalent to PAR 1110.2	Not significant, less than PAR 1110.2	Significant Equivalent to PAR 1110.2
Toxic	Significant	Not significant, less than PAR 1110.2	~~Not s~~Significant, same as PAR 1110.2	Not significant, less than PAR 1110.2	~~Not s~~Significant, same as PAR 1110.2
Greenhouse Gas	Not significant beneficial effect	Not significant no beneficial effect	Not significant equivalent to PAR 1110.2	Not significant no beneficial effect	Not significant less than PAR 1110.2
Energy					
Electricity	Not significant	Not significant no Impact	Not significant, same as PAR 1110.2	Not significant, less than PAR 1110.2	Not significant Equivalent to PAR 1110.2
Natural Gas	Not significant beneficial effect	Not significant less than PAR 1110.2	Not significant Equivalent to PAR 1110.2	Not significant, less than PAR 1110.2	Not significant Equivalent to PAR 1110.2
Diesel	Not significant	Not significant no Impact	Not significant, less than PAR 1110.2	Not significant, less than PAR 1110.2	Not significant Equivalent to PAR 1110.2
Hazards/Hazardous Material	Significant	Not significant no Impact	Significant, same as PAR 1110.2	Not significant, less than PAR 1110.2	Significant Equivalent to PAR 1110.2
Solid/Hazardous Waste	Not significant	Not significant no Impact	Not significant, same as PAR 1110.2	Not significant, same as PAR 1110.2	Not significant Equivalent to PAR 1110.2

CHAPTER 2

PROJECT DESCRIPTION

PROJECT LOCATION

The SCAQMD has jurisdiction over an area of 10,473 square miles (referred to hereafter as the district), consisting of the four-county South Coast Air Basin and the Riverside County portions of the Salton Sea Air Basin (SSAB) and the Mojave Desert Air Basin (MDAB). The Basin, which is a subarea of the SCAQMD's jurisdiction, is bounded by the Pacific Ocean to the west and the San Gabriel, San Bernardino, and San Jacinto Mountains to the north and east. The 6,745 square-mile Basin includes all of Orange County and the nondesert portions of Los Angeles, Riverside, and San Bernardino counties. The Riverside County portion of the SSAB and MDAB is bounded by the San Jacinto Mountains in the west and spans eastward up to the Palo Verde Valley. The federal nonattainment area (known as the Coachella Valley Planning Area) is a subregion of both Riverside County and the SSAB and is bounded by the San Jacinto Mountains to the west and the eastern boundary of the Coachella Valley to the east (Figure 2-1).

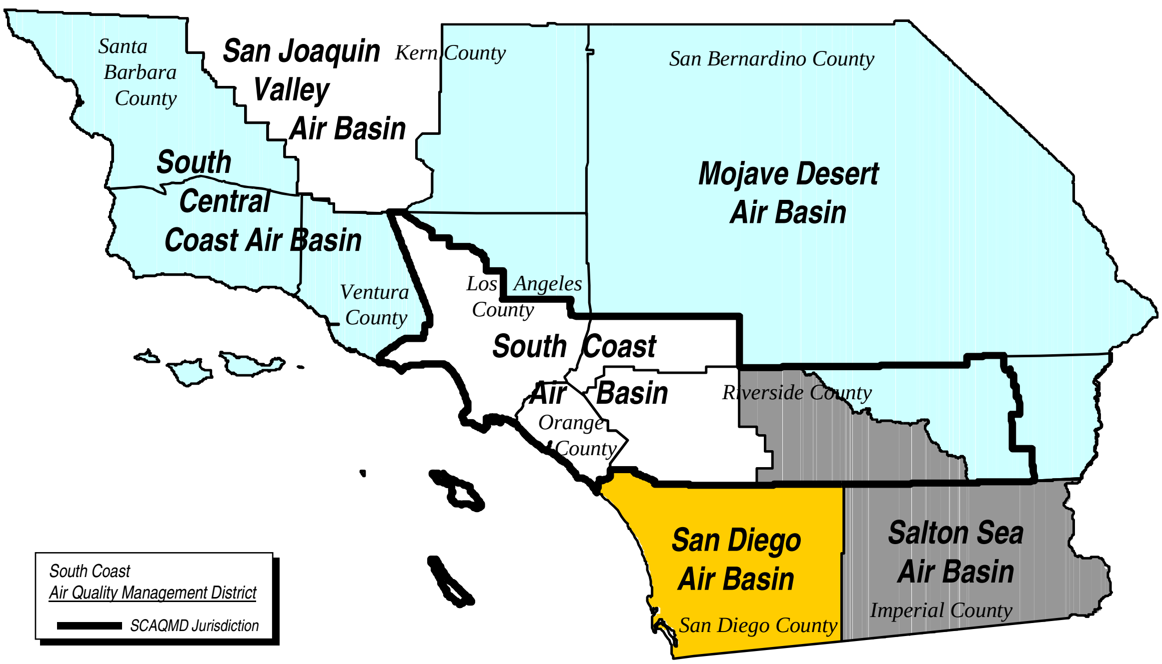


Figure 2-1
South Coast Air Quality Management District

BACKGROUND

Rule 1110.2 was originally adopted in August 1990 to control NOx, carbon monoxide (CO), and VOC emissions from gaseous and liquid-fueled internal combustion engines (ICEs). For all stationary and portable engines over 50 brake horsepower (bhp), it required that either 1) NOx emissions be reduced over 90 percent, or; 2) the engines be permanently removed from service or replaced with electric motors. It was amended in September 1990 to clarify rule language. Rule 1110.2 was then amended in August and December of 1994 to modify the CO monitoring requirements and to clarify rule language. The amendment of November 1997 eliminated the requirement for continuous monitoring of CO, reduced the source testing requirement from once every year to once every three years, and exempted nonroad engines, including portable engines, from most requirements. The last amendment in June 2005 made the previously exempt agricultural engines subject to the rule.

United States Environmental Protection Agency's Disapproval of Rule 1110.2

SCAQMD rules and regulations are submitted to both the California Air Resources Board and the United States Environmental Protection Agency (EPA) for approval and incorporation into the State Implementation Plan (SIP). EPA proposed the disapproval of Rule 1110.2, which means it cannot be incorporated into the SIP and, therefore, cannot contribute to the SCAQMD's attainment demonstration for state and national ambient air quality standards. EPA recommended the following to enable approval of the rule[4]:

- An inspection and monitoring plan similar to CARB' Reasonably Available Control Technology/Best Available Retrofit Control Technology (RACT/BARCT) document;
- Source testing every two years or 8,760 hours;
- Source testing at peak load as well as at under typical duty cycles; and
- Justification of the exemptions for engines at ski resorts, the far eastern portion of Riverside County, and San Clemente Island.

PROJECT OBJECTIVE

PAR 1110.2 partially implements 2007 AQMP Control Measure MSC–01 – Facility Modernization, which requires facilities not participating in the NOx Regional CLean Air Incentives Market (RECLAIM) Program to retrofit or replace existing equipment at the end of a predetermined life span to achieve NOx emissions equivalent to BACT. In addition to achieving NOx emission reductions, one of the objectives of PAR 1110.2 is to achieve further VOC and CO emission reductions based on the cleanest available technologies. PAR 1110.2 would also increase engine compliance through improved monitoring, recordkeeping and reporting. PAR 1110.2 would partially implement SB 1298 distributed generation emission standards for new electrical generating engines. Finally, a major objective of PAR 1110.2 is to address issues identified by EPA relative to the existing version of Rule 1110.2, so it can be approved for incorporation into the SIP ~~(see preceding discussion)~~.

REGULATORY BACKGROUND

There are three levels of regulatory requirements that apply to the affected facilities: 1) federal requirements (EPA); 2) state (CARB, and, 3) local (the SCAQMD). The following

[4] Memorandum from Andrew Steckel of EPA to Laki Tisopulos of SCAQMD dated March 31, 2005.

is an overview of federal, state and local regulatory programs that are applicable to the affected operations.

Federal Requirements

The federal Clean Air Act requires the SCAQMD to adopt an AQMP that identifies a control strategy to demonstrate compliance with the federal ambient air quality standards. To address this federal mandate, the 2007 AQMP for the district included AQMP Control Measure MCS-01 – Facility Modernization, which requires facilities to retrofit or replace their equipment to achieve emission levels equivalent to BACT. In addition, there are other federal requirements that apply to internal combustion engines. The following is a brief summary of these requirements.

<u>New Source Performance Standards</u>

In a Consent Decree, EPA began working on New Source Performance Standards (NSPS) for new stationary ICEs. EPA recently finalized regulations for compression-ignition (CI or diesel) engines and has proposed regulations for spark-ignition (SI) engines. The Consent Decree requires standards for SI engines to be promulgated by December 2007.

<u>Compression-Ignition Engine New Source Performance Standards (NSPS)</u>

On July 11, 2006, EPA issued final regulations to limit NOx, PM, CO and non-methane hydrocarbon (NMHC) emissions from stationary CI engines, which are contained in Subpart IIII of 40 CFR 60. The compression-ignition (CI) engines NSPS establishes requirements for manufacturers, owners, and operators of new (i.e. engines whose construction, modification or reconstruction began after July 11, 2005) stationary CI engines. The CIE NSPS requires the use of on-engine controls, after treatment and lower sulfur fuel to achieve the same emission standards as required for nonroad engines described in a later section. It also specifies monitoring, reporting, recordkeeping, and testing requirements. Except for CO, the emission standards are not as stringent as the limits in the current Rule 1110.2 until the Tier 4 emission standards go into effect from 2011 to 2015.

<u>Spark-Ignition Engine New Source Performance Standards (SIE NSPS)</u>

On June 12, 2006, EPA issued proposed NSPS for stationary spark-ignition engines (SIE) that would apply to new (i.e. engines whose construction, modification or reconstruction began after a standard is proposed) stationary SI engines. The proposed new Subpart JJJJ of 40 CFR 60 will limit NOx, NMHC, and CO emissions. It also specifies monitoring, reporting, recordkeeping, and testing requirements.

The SIE NSPS requires the use of on-engine controls or after treatment to achieve the emission standards. For all SI engines less than 25 hp, gasoline SI engines and rich-burn propane engines, the emission limits are those in the EPA regulations for nonroad SI engines (40 CFR Parts 90 and 1048).

EPA NOx emission limits have been proposed for large natural gas, digester gas and landfill gas engines that are less stringent than the current Rule 1110.2. Facility operators in the district will be held to the more stringent SCAQMD Rule 1110.2 emission limit. The proposed CO and NMHC limits for the same engines are more stringent than the current Rule 1110.2, but not as stringent as SCAQMD BACT for new engines. The emission limits start at 463 ppmvd CO and 203 ppmvd NMHC and drop to 232 ppmvd CO and 142 ppmvd NMHC by 2010/2011 for natural gas engines[5]. Landfill and digester gas engines are limited to 579 ppmvd CO and 203 ppmvd NMHC.

National Emission Standards for Hazardous Air Pollutants (NESHAP)

On June 15, 2004, the EPA issued a final rule to reduce hazardous air pollutant emissions (formaldehyde, acrolein, methanol, and acetaldehyde) from stationary engines, in the National Emission Standard for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines (RICE NESHAP), Subpart ZZZZ of 40 CFR 63. The RICE NESHAP establishes requirements for large (greater than 500 horsepower) stationary engines, both CI and SI, located at major sources of hazardous air pollutants.

The RICE NESHAP requires installation of oxidation catalysts on lean-burn engines and three-way catalysts (also known as non-selective catalytic reduction (NSCR) catalysts) to reduce hazardous air pollutants and CO and specifies recordkeeping, monitoring, and testing requirements. The RICE NESHAP requires that:

- Existing and new 4-stroke rich burn (4SRB) engines either reduce formaldehyde by 76 percent or limit the formaldehyde concentration to 350 parts per billion.
- New 2-stroke lean burn (2SLB) engines either reduce carbon monoxide (CO) by 58 percent or limit the formaldehyde concentration to 12 parts per million.
- New 4-stroke lean burn (4SLB) engines either reduce CO by 93 percent or limit the formaldehyde concentration to 14 parts per million.
- New compression ignition (CI) engines either reduce CO by 70 percent or limit the formaldehyde concentration to 580 parts per billion.

Formaldehyde and CO are surrogates for reducing the air toxics of concern from RICE. Therefore, by reducing formaldehyde and CO, facilities also will reduce other organic air toxics. Similarly, reducing CO will reduce formaldehyde and vice versa.

Only two facility operators within the district have notified EPA that they are subject to the major source RICE NESHAP: the natural gas storage facilities in Northridge and Santa Clarita operated by Southern California Gas Company.

On June 12, 2006, EPA proposed amendments to Subpart ZZZZ that will apply to new or reconstructed RICEs less than 500 hp at major sources, and new or reconstructed RICEs at minor sources. In general these RICEs will only have to comply with the proposed RICE SI NSPS or the adopted RICE CI NSPS. The exception is that new SI 4SLB RICEs from 250 to 500 hp (not including digester or landfill gas fired RICEs) will have to reduce CO by 93 percent or limit the formaldehyde concentration to 14 ppmvd.

Nonroad Engines

EPA regulates new nonroad engines, which include: engines that propel off-road equipment such as trains and bulldozers, and; portable engines that drive generators, wood chippers,

[5] Corrected to 15 percent O2 and assuming an engine efficiency of 30 percent based on higher heating value of the fuel.

and other equipment, and that are moved from place to place. Nonroad engines include CI and SI engines using diesel fuel, propane, gasoline and other fuels.

The Nonroad Preemption

The Clean Air Act Amendments of 1990 limit the ability of states and local districts to regulate nonroad engines. Only EPA can set emission standards for new construction and farm equipment under 175 hp. Federal regulations[6] allow California to regulate all other nonroad engines with an authorization from EPA. Other states cannot regulate the use of nonroad engines, but can adopt California standards.

Nonroad Diesel Engine Regulations

EPA has been regulating new nonroad diesels since 1996 pursuant to 40 CFR 89 Subpart A, Appendix A and 40 CFR 85 Subpart Q. Tier 1, Tier 2 and Tier 3 standards are in effect or are partly in effect and recently adopted and stringent Tier 4 standards will go into effect in the next decade. The emission standards vary by engine size, but as an example Table 2-1 shows the standards for nonroad diesel engines from greater or equal to 100 bhp to less than 175 bhp.

Table 2-1
EPA Nonroad Diesel Engine Emission Standards (grams/bhp-hr)
175 ≤ hp < 300

Tier	Implementation Date	CO	NMHC	NOx + NMHC	NOx	PM
Tier 1	1996	8.5	1.0	-	6.9	-
Tier 2	2003	2.6	-	4.9	-	0.15
Tier 3	2006	2.6	-	3.0	-	0.15
Tier 4	2012-2014	2.6	0.14	-	0.30	0.015

Nonroad Spark-Ignited (SI) Engine Regulations

EPA regulated new nonroad SI engines over 25 hp since 2004 pursuant to 40 CFR 1048. Most of these engines use liquefied petroleum gas (propane), with others operating on gasoline or natural gas. EPA adopted the two tiers of emission standards shown in Table 2-2. The first tier of standards, which became effective in 2004, is based on a simple laboratory measurement using steady-state procedures. The Tier 1 standards are the same as those adopted earlier by CARB for engines used in California. The Tier 2 standards, which became effective in 2007, are based on transient testing in the laboratory, which ensures that the engines will control emissions when they operate under changing speeds and loads in the different kinds of equipment. EPA includes an option for manufacturers to certify their engines to a less stringent CO standard if they certify an engine with lower HC plus NOx

[6] 40 CFR 89, Subpart A, Appendix A and 40 CFR 85, Subpart Q

emissions. In addition to these exhaust-emission controls, manufacturers must take steps starting in 2007 to reduce evaporative emissions, such as using pressurized fuel tanks.

Table 2-2
EPA SI Engine Emission Standards (grams/bhp-hr)

Tier	Implementation Date	HC + NOx	CO
Tier 1	2004	3.0	37
Tier 2	2007	2.0	4.4

Starting with Tier 2, EPA adopted additional requirements to ensure that engines control emissions during all kinds of normal operation in the field. Tier 2 engines must have engine diagnostic capabilities that alert the operator to malfunctions in the engine's emission-control system.

State Requirements

The California Health and Safety Code also requires the SCAQMD to adopt an AQMP that identifies a control strategy demonstrating progress towards achieving the state ambient air quality standards. The CARB Governing Board adopted the SCAQMD's 2007 AQMP without substantial modification. CARB must submit the 2007 AQMP to EPA for final approval and incorporation into the SIP. The 2007 AQMP includes the control strategy MCS-01 – Facility Modernization, which proposes that existing equipment be retrofitted or replaced with BACT at the end of a pre-determined lifespan. PAR 1110.2 would require that existing ICEs be retrofitted or replaced with equipment that can meet BACT concentration standards.

Senate Bill 1298

Senate Bill 1298[7] was adopted in 2000 by the California state legislature to close a loophole for small electric generators that were exempt from local district permits and not required to have emission controls. In accordance with the law, CARB adopted the Distributed Generation Certification Program[8] for small generators that are exempt from local district permitting requirements. Small generators include ICE generators of 50 hp or less, microturbines, and fuel cells. As of January 1, 2007 these electrical generation technologies may only be sold in California if they are certified by CARB to have emissions equivalent to, or better than large central generating stations equipped with BACT. SB 1298 also established a goal to have local districts require permitted distributed generation (DG) equipment meet BACT levels by the earliest practicable date.

CARB Guidance for Stationary Spark-Ignited Engines

In 2001, CARB published "Determination of Reasonably Available Control Technology and Best Available Retrofit Control Technology for Stationary Spark-Ignited Internal Combustion Engines" as guidance for local air districts in adopting rules for stationary spark-ignited engines. Because of compliance problems with engines throughout the state,

[7] Sections 41514.9 and 41514.10 of the California State Health and Safety Code
[8] Sections 94200-94214, in Article 3, Subchapter 8, Chapter 1, Division 3 of Title 17, California Code of Regulations

CARB's publication recommended more frequent source testing than is currently required in Rule 1110.2 and an Inspection and Monitoring Plan requiring periodic monitoring and maintenance, including the use of a portable emissions analyzer.

Air Toxic Control Measures for Diesel Engines

CARB has adopted Air Toxic Control Measures (ATCMs) for both stationary and portable diesel engines. The purpose of these ATCMs is primarily to reduce diesel PM because it has been classified as a carcinogen by CARB. However, the ATCMs often result in emission reductions of other pollutants as well.

Stationary Diesel ATCM – SCAQMD Rule 1470

SCAQMD has adopted Rule 1470 to implement the state ATCM for stationary diesel engines. Rule 1470 requires emergency diesel engines to: limit the annual operating hours for maintenance and testing; avoid operation during school hours when near a school: and install a diesel particulate filter when located within 328 feet of a school. Non-emergency diesel engines, with some notable exceptions, must also install a diesel particulate filter to meet the required emission limit.

Existing stationary agricultural engines were not subject to the original stationary diesel ATCM, but on November 16, 2006, CARB adopted the first of several amendments to the ATCM that make existing stationary agricultural engines subject to the ATCM requirements. The most recent amendments to the ATCM relative to existing stationary agricultural engines have not yet received approval by the Office of Administrative Law. The ATCM requires the following for stationary agricultural diesel engines, not including wind machines, emergency engines, or engines less than50 hp:

- Except for generator sets, uncertified engines from 51 to 750 hp must meet Tier 3 diesel PM emission requirements by December 31, 2010 or December 31, 2011, depending on horsepower. The compliance requirements of this ATCM will cause operators of engines eligible for the January 1, 2014 compliance date allowed by paragraph (h)(12) of PAR 1110.2 to have to retrofit or replace equipment sooner to comply with the ATCM.
- Generator sets, uncertified engines over 750 hp, and Tier 1 or Tier 2 engines must meet Tier 4 diesel PM emission requirements by December 31, 2014 or December 31, 2015, depending on horsepower. By these dates these same engines will already be required to be in compliance with PAR 1110.2.
- Operators must register their engines with local air pollution control districts by submitting detailed information about each engine. The regulation also allows local districts to charge fees for this registration.

Portable Diesel ATCM

CARB adopted a portable diesel ATCM (§§93116 through 93116.5 of Title 17 of the California Code of Regulations) on February 24, 2004, which will have a substantial effect on portable diesel engines, including agricultural portable engines, greater than 50 hp. The ATCM requirements include:

- As of January 1, 2006, any newly permitted portable diesels must be certified to the current model year standards (Tier 2 or Tier 3 depending on the horsepower). However, CARB recently adopted emergency rules to loosen this requirement to allow resident Tier 1 and 2 engines to continue to operate.
- By January 1, 2010, uncertified portable diesels may no longer be used in California.
- Operators of portable diesel fleets must reduce the fleet average PM emissions to increasingly lower levels by 2013, 2017 and 2020 by engine replacements or retrofit of PM control devices.

Agricultural portable engines are subject to this ATCM, although CARB is developing regulations for agricultural portable engines.

CARB Portable Equipment Registration Program (PERP) Regulation

Health & Safety Code §§41750-41755 (Assembly Bill 531), effective January 1, 1996, required CARB to adopt regulations to establish a statewide registration program for portable engines and other equipment. CARB adopted the regulation on March 27, 1997. Portable engine owners or operators may register under the statewide program or get a permit from SCAQMD. Those that register with CARB are exempt from AQMD permits and emission requirements. As of January 1, 2006, newly registered engines must be certified to the current model year emission standards (Tier 2 or Tier 3 depending on the horsepower). However, CARB adopted emergency rules to loosen this requirement to allow resident Tier 1 and 2 engines to continue to be registered. Portable agricultural engines are not eligible for the CARB PERP program.

Off-Road Diesel Engines

CARB began regulating new off-road[9] diesel engines before EPA, but later harmonized its regulations in Title 13, Chapter 9, Article 4 of the California Code of Regulations (CCR) with EPA nonroad diesel emission standards. On December 9, 2004, CARB approved amendments to incorporate EPA Tier 4 standards into state law. The regulation is not final, however, until approved by the Office of Administrative Law. The NOx, non-methane hydrocarbon and PM emission standards will be the same as EPA's, but there are some minor differences in areas other than the emission standards.

Off-Road Spark-Ignited (SI) Engines

CARB has been regulating new off-road SI engines over 25 hp since 2001 in Title 13, CCR, Chapter 9, Article 4.5. In May 2006, CARB adopted standards consistent with EPA for 2007 to 2009 model years, and more stringent standards starting in 2010. The emission standards are shown in Table 2-3.

[9] EPA uses the term nonroad for the same purpose.

Table 2-3
CARB Off-Road SI Engine Emission Standards (grams/bhp-hr)

Implementation Date	Engine Displacement	HC + NOx	CO
2002	≤ 1.0 Liters	9.0	410
2001-2003	> 1.0 Liters	3.0	37
2007-2009	> 1.0 Liters	2.0	3.3
2010	> 1.0 Liters	0.6	15.4

CARB also adopted fleet average emissions standards for forklifts, scrubbers/sweepers, industrial tow tractors and airport ground support equipment. Starting in 2009 fleet operators will have to reduce average HC plus NOx emissions by retrofits or replacements. By 2013, fleet average emissions will have to be reduced to 1.5 to 3.4 g/bhp-hr, depending on the type of fleet.

Distributed Generating Technologies that Meet CARB 2007 DG Standards

Distributed energy resources are small-scale power generation technologies (typically in the range of three to 10,000 kW) located close to where electricity is used (e.g., a home or business) to provide an alternative to or an enhancement of the traditional electric power system. The distributed generating (DG) certification program requires manufacturers of electrical generation technologies that are exempt from district permit requirements to certify their technologies to specific emission standards before they can be sold in California. CARB has certified that the DG equipment shown in Table 2-4 meet the 2007 standards.

Table 2-4
Certified Technologies to CARB 2007 DG Standards

Company Name	Technology
United Technologies Corporation Fuel Cells	200 kW, Phosphoric Acid Fuel Cell
FuelCell Energy, Inc.	250 kW, DFC300A Fuel Cell
Plug Power Inc.	5 kW, GenSys^{TM} 5C Fuel Cell
FuelCell Energy, Inc.	1 MW, DFC1500 Fuel Cell
Ingersoll-Rand Energy Systems	250 kW, 250SM Microturbine
FuelCell Energy, Inc.	300 kW, DFC300MA Fuel Cell
ReliOn, Inc.	2 kW, T-2000 hydrogen-fueled fuel cell
ReliOn, Inc.	1.2 kW, T-1000 hydrogen-fueled fuel cell

The following DG technologies do not require CARB certification because they are normally required to be permitted by the SCAQMD. The following equipment can, however, also meet CARB's 2007 emission standards.

- Kawasaki GPB15X Gas Turbine–1.423 gross MW at ISO conditions (sea level, 59^{o}F), guaranteed emission limits of 2.5 ppm NOx, six ppm CO and two ppm VOC, all dry basis, corrected to 15 percent O2, down to 70 percent of rated load. These emission limits together with heat input of 20.7 MMBtu/hr (LHV) and 53.7 percent waste heat recovery specified by the manufacturer meet the CARB 2007 standards.

- Large combustion gas turbines with combined heat and power (CHP) are similar to the central station combined-cycle power plants that are the basis of the 2007 CARB DG standards.

Facility operators may install other DG technologies such as: zero-emission solar or wind DG. All of the preceding technologies are either inherently low-emission or will have CEMS to assure proper operation of their add-on emission controls.

Local SCAQMD Requirements

ICEs are required to comply with SCAQMD administrative or prohibitory rules such as Rule 203 – Permit to Operate, Rule 401 – Visible Emissions, Rule 402 – Nuisance, Rule 404 – Particulate Matter- Concentration, and Rule 405 – Solid Particulate Matter – Weight. In addition to Rule 1110.2, other rules that control emissions from ICEs are summarized in the following subsections.

Regulation XIII

Federal and state laws require the development and implementation of New Source Review (NSR) programs to ensure that the operation of new, modified, or relocated stationary emission sources in nonattainment areas does not interfere with the attainment and maintenance of National Ambient Air Quality Standards (NAAQS). Local NSR programs must, at a minimum, comply with the requirements established pursuant to federal and state law. The general requirements of NSR programs include: (1) pre-construction review; (2) the installation of air pollution control equipment; and, (3) the mitigation of emission increases by providing emission offsets.

To satisfy requirement (2), the SCAQMD requires BACT for any emissions increase greater than one pound per day from a new, modified, or relocated source within the district. BACT has historically been defined in SCAQMD NSR rules as the most stringent emission limit or control technology which has been achieved in practice for that category or class of source; or contained in a SIP; or other limit that is technologically feasible and cost-effective. SCAQMD rules require BACT for all sources to be at least as stringent as the lowest achievable emission rate (LAER) as defined in the federal Clean Air Act (CAA).

Rule 1470

Rule 1470 applies to stationary compression ignition engines which are engines that remain in one location for 12 months or longer. Rule 1470 primarily regulates DPM emissions by establishing fuel use specifications, operating requirements and PM emission limits for existing diesel-powered engines. Rule 1470 also established emission standards for new stationary diesel engines less than or equal to 50 brake horsepower (bhp) installed after January 1, 2005 based on Title 13 §2423. Title 13 §2423 includes emission standards for NOx, VOC, NOx and VOC combined, CO and PM. Rule 1470 also includes recordkeeping, reporting and monitoring requirements, a compliance schedule, test methods and exemptions.

Although Rule 1470 is based on CARB's ATCM, it contains more stringent requirements for stationary diesel-fueled emergency standby and prime engines located on school grounds or 100 meters or less from existing schools, resulting in reduced emissions of DPM and cancer risk to neighboring schools. Rule 1470 also prohibits non-emergency use (e.g., testing) of diesel emergency standby engines located on school grounds or 100 meters or less from existing schools when school activities are taking place.

Regulation XX – RECLAIM

In 1993 SCAQMD adopted Regulation XX – RECLAIM. This regulation established a cap-and-trade NOx and SOx trading market, with declining annual emission reduction requirements, regulating more than 300 of the largest NOx and SOx sources in SCAQMD's jurisdiction. Operators of affected facilities are exempt from the requirements of specified NOx and SOx stationary source-specific SCAQMD Rules. The program allows facility operators flexibility with regard to complying with the declining NOx and SOx annual allocations, either through installing air pollution control equipment, purchasing RECLAIM trading credits, or a combination of the two.

RECLAIM facility operators are not subject to the source-specific NOx control requirements of Rule 1110.2. RECLAIM facility operators may decide as part of their compliance options to comply with their annual allocation under the program to install air pollution control equipment on ICEs. Although ICEs in the RECLAIM program are not subject to Rule 1110.2 NOx emission control requirements, they are still subject to the VOC and CO emissions control requirements of Rule 1110.2.

SCAQMD BACT Guidelines

NOx, CO and VOC emission levels for stationary engines that are required by SCAQMD's non-major source BACT guidelines are shown in Table 2-5. These limits are typically met by rich-burn engines with a three-way catalyst (TWC), along with an air-to-fuel ratio controller (AFRC). Lean-burn engines generally come with low-NOx combustion modifications built into the engine by the manufacturer to reduce the emissions and then use SCR plus oxidation catalyst to reduce emissions to BACT levels.

Table 2-5
SCAQMD BACT Guidelines for Stationary Engines at Non-major Polluting Facilities

	PPMVD, corrected to 15% O2					
	Uncontrolled Emission		BACT		Percent Reduction by Control Technology	
Criteria Pollutant	Rich-Burn	Lean-Burn	Rich-Burn (NSCR)*	Lean-Burn (SCR + CatOx)	Rich-Burn (NSCR), %	Lean-Burn (SCR + CatOx), %
NOx	590	1090	10	9	98+	99+
CO	1629	136	69	33	95+	75+
VOC	23	91	29	25	---	73+

*Assuming engine is 30 percent efficient (HHV basis).

PROJECT DESCRIPTION

Summaries of the proposed amendments to Rule 1110.2 by subdivision are provided in the following subsections. A copy of PAR 1110.2 can be found in Appendix B.

Applicability

PAR 1110.2 applies to all stationary and portable engines over 50 rated bhp.

Definitions

This subdivision lists keywords related to gaseous- and liquid fueled engines and defines them for clarity and to enhance enforceability. A new definition for "oxides of nitrogen" and revised definition of "approved emission control plan" and engine are proposed to simply clarify the intent of the rule. New definitions for "net electrical energy", "operating cycle", "rich-burn engine with a three-way catalyst", "lean-burn engine" and "useful heat recovered" were developed to support the new requirements discussed later.

The definition of "engine" is revised to clarify that engines used to control VOC emissions from soil vapor extraction are subject to Rule 1110.2.

Requirements

Operators of affected operations would be required to comply with the following requirements by January 4, 2008 unless otherwise stated.

Stationary Engines

Reduction of the Emission Concentration Limits

Subparagraphs (d)(1)(B) and (d)(1)(C) currently limit NOx, VOC and CO concentrations to 36 (less than 500 bhp) or 45 (greater than 500 bhp), 250 and 2000 parts per million, dry volume (ppmvd) respectively for non-biogas-fired (non-landfill/non-digester gas) engines. The proposed amendments will reduce these limits by 2010 or 2011 to levels comparable to current BACT (see Table 2-6). This section provides a new exception from concentration limits effective on and after July 1, 2010 for engines that operate less than 500 hours per year or use less than $1x10^9$ Btu per year of fuel. For two stroke engines with oxidation catalyst and insulated exhaust ducts and catalyst housing, case-by-case CO and VOC limits may be established by the Executive Officer with USEPA approval.

Revisions to the Efficiency Correction for Stationary Engines

The current rule in subparagraph (d)(1)~~©~~(c) allows most stationary engines listed in Table III of the rule, to upwardly adjust the NOx and VOC ppmvd emission limits based on the actual engine efficiency or the manufacturer's rated efficiency. More efficient engines are allowed higher ppmvd limits.

The proposed amended subparagraph (d)(1)~~©~~(c) limits the efficiency correction to biogas-fired engines, requires that the correction be based on actual efficiency from (American Society of Mechanical Engineers) ASME test procedures, requires engines to use at least 90 percent biogas on a monthly basis, and requires the corrected emission limits to be stated on the operating permit. An allowance for burning more than 10 percent natural gas is provided if the only alternative to limiting natural gas to 10 percent would be shutting down engine and flaring more landfill or digester gas. In response to comments, several changes have been made to PAR 1110.2. The Executive Officer may approve more than the 10 percent natural gas if the 10 percent limit would result in more biogas flaring; or if more than 10 percent natural gas is required in order for an engine's waste heat boiler to provide enough thermal energy for a sewage treatment plant, and if other boilers are unable provide the needed thermal energy. Also, the 10 percent limit will be based on a facility average, rather than for each individual engine. Finally, the calculation of the monthly facility average natural gas percentage may exclude natural gas used during the following situations: during: electrical outages; during Stage 2 or higher electrical emergencies called by the California Independent System Operator; and when rainfall causes a sewage treatment plant to exceed its design capacity. Once an engine complies with the emission limits effective July1, 2012 there will be no limit on the percentage of natural gas burned.

Table 2-6
Proposed Concentration Limits for Non-Biogas Engines

CONCENTRATION LIMITS FOR NON- BIOGAS-FIRED ENGINES			
Engine Size (bhp)	NO_x (ppm)[1]	VOC (ppm)[2]	CO (ppm)[1]
≥ 500 < 500	36 45	250	2000
CONCENTRATION LIMITS EFFECTIVE JULY 1, 2010			
Engine Size (bhp)	NO_x (ppm)[1]	VOC (ppm)[2]	CO (ppm)[1]
≥ 500 < 500	11 45	bhp ≥ 500: 30 bhp < 500: 250	bhp ≥ 500: 250 bhp < 500: 2000
CONCENTRATION LIMITS EFFECTIVE JULY 1, 2011			
Engine Size (bhp)	NO_x (ppm)[1]	VOC (ppm)[2]	CO (ppm)[1]
All Engines	11	30	250

1 Corrected to 15 percent oxygen on a dry basis and averaged over 15 minutes.
2 Measured as carbon, corrected to 15 percent oxygen on a dry basis and averaged over 30 minutes.

©

Emission Standards for Biogas Engines

In addition to allowing biogas engines to continue to use an efficiency correction factor, the following emission concentration limits are proposed for biogas-fired engines:

Table 2-7
Proposed Concentration Limits for Biogas Engines

Concentration Limits For Landfill and Digester Gas-Fired Engines			
Engine Size (bhp)	NO_x (ppm)[1]	VOC (ppm)[2]	CO (ppm)[1]
≥ 500 < 500	bhp ≥ 500: 36 x ECF[3] bhp < 500: 45 x ECF[3]	Landfill Gas: 40 Digester Gas: 250 x ECF[3]	2000
Concentration Limits Effective July 1, 2012			
Engine Size (bhp)	NO_x (ppm)[1]	VOC (ppm)[2]	CO (ppm)[1]
All Engines	11	30	250

1 Corrected to 15 percent oxygen on a dry basis and averaged over 15 minutes.
2 Measured as carbon, corrected to 15 percent oxygen on a dry basis and averaged over 30 minutes.
3 ECF is the efficiency correction factor.

Initially, only the VOC limit for landfill gas engines would change, to be consistent with other current requirements. In 2012, the emissions limits would drop to BACT levels, just as is proposed for non-biogas engines, except for CO. These emission limits would become effective provided that SCAQMD staff conducts a technology assessment and reports to the Governing Board by July 2010.

Air-to-Fuel Ratio Controllers

The current rule doesn't require an air-to-fuel ratio controller (AFRC) for ICEs. The proposed amendments require ICEs without a CEMS or a Regulation XX (RECLAIM) approved CEMS to install an AFRC with an oxygen sensor and feedback control, or other equivalent technology approved by the Executive Officer, CARB and USEPA.

Emission Standards for New Non-Emergency Electrical Generation Engines

New non-emergency electrical generation engines are proposed in subparagraph (d)(1)(F) to be subject to the emission standards in the following table.

Table 2-8
Proposed Emission Limits for New Electrical Generation Engines

Pollutant	Emission Limit (lbs/MW-hr)
NOx	0.07
CO	0.2 ~~0.10~~
VOC	0.10 ~~0.02~~

These emission standards do not apply to biogas engines or engines installed before the date of rule adoption or for which an application has been deemed complete before October 1, 2007 and engines installed by an electric utility on Santa Catalina Island. In addition, notwithstanding Rule 2001, these emission standards do not apply to NOx emissions from new non-emergency engines driving electrical generators subject to Regulation XX (RECLAIM).

For engines that do not produce combined heat and power (CHP), the emission standards are based on the net electrical megawatt-hours (MWe-hours) produced. CHP (also know as cogeneration) engines may also take credit for the thermal megawatt-hours (MWth-hours) of useful heat produced, with one MWth-hour for each 3.4 million British thermal units (BTU). The thermal energy could take the form of hot water, steam or other medium.

For CHP engines, the operator will choose short-term emission limits in pounds per MWe-hours that the engine must meet at all times. The operator will also choose an annual electrical energy factor (EEF), such that when the short-term emission limit is multiplied by the annual EEF, the result does not exceed the values in the Table 1-3. The EEF is the annual net electrical energy produced divided by the sum of the electrical and thermal energy produced. The operator will have to also meet the annual EEF limit.

Portable Engines

Staff proposes to remove the emission limits and related requirements for portable engines in subparagraph (d)(2)(A) and add a reference to the California Air Resources Board (CARB)-adopted, portable diesel (Airborne Toxic Control Measures) ATCM and the Large Spark-Ignition Fleet Requirements, to which some portable engines are subject.

Compliance

Paragraphs (e)(1) and (e)(3) are proposed for deletion because they are not necessary. New paragraph (e)(2) includes schedules that will allow time for review and approval of applications for permits to construct, CEMS application, and I&M plan applications. Public agencies will be allowed one more year than the dates on the rule schedule for CEMS applications except for landfill or digester gas engines. New paragraphs (e)(3) through (e)(7) propose compliance schedules for non-agricultural engines required to meet the future emission limits, the stationary engine continuous emission monitoring system (CEMS) requirements, and the inspection and monitoring (I&M) plans. .

New engines will be required to comply with the new CEMS and I&M requirements when they begin operation.

Facilities with more than five engines without air-to-fuel ratio controllers are allowed an additional three months to install equipment on up to half of affected engines. The other facility operators that need to install AFRCs would follow the regular schedule which is one year from the date of rule adoption. An exception has been added for facilities that will be removing engines from service or replacing with electric motor and will not be required to comply with the earlier steps of this subdivision.

Monitoring, Testing and Recordkeeping

The primary focus of the proposed amendments in this subdivision is to improve the poor compliance record of stationary engines.

Additional CEMS Requirements

The existing subparagraph (f)(1)(A) requires 1,000 hp engines and larger, that produce two million bhp-hours per year or more to have a NOx CEMS that measures and records exhaust gas concentrations both uncorrected and corrected to 15 percent oxygen on a dry basis and have data gathering and retrieval capability approved by the Executive Officer. The proposed amendments add CO emissions monitoring back into the rule in subparagraph (f)(1)(A), as it was before the 1997 amendment, but only for rich-burn engines.

In addition, the CEMS requirement will be extended to stationary engines at facilities with multiple engines at the same location (within 75 feet of each other, measured from engine block to engine block) that have a cumulative stationary engine horsepower rating of 1,500 bhp or more. However, the following engines will not be counted toward the cumulative hp rating: engines rated at less than 500 bhp; standby engines that are limited by permit conditions to only operate when other primary engines are not operable; engines that are limited by permit conditions to operate less than 1,000 hours per year or a combined fuel usage of less than 8 x 10^9 Btu per year (higher heating value); and engines already required to have a CEMS.

To avoid circumvention of the requirements, groups of existing engines within 75 feet are based on their location on October 1, 2007. New engines must not be located farther than 75 feet from another engine unless the operator demonstrates to the Executive Officer that there is a space limitation or operational need.

Also, in cases where an operator has multiple engines for reliability purposes, with some as standby, the proposed rule would not require a group of engines to have a CEMS if there are permit conditions that limit the simultaneous operation in such a way that the maximum combined rating does not exceed 1,500 bhp.

The 500 bhp exception will reduce the number of new CEMS to less than 100. The other exceptions may reduce the number further, but staff isn't certain by how much.

Lean-burn engines are excluded from the requirement of a CO CEMS. Also excluded from a CO CEMS are engines in RECLAIM that are not required to have a NOx CEMS by Regulation XX.

To reduce the cost, the CEMS can be time-shared between all engines < 1000 hp.

Clause (f)(1)(A)(ix) will allow current CEMs operators to take their CEMS out of operation for up to two weeks in order to add the required CO CEMs.

New clauses (f)(1)(A)(vi) and (f)(1)(A)(vii) provides several exceptions to Rule 218 for the required new CEMS to make timesharing more feasible, and streamline the requirements. They include: allowing digital storage of data, instead of a strip chart; requiring relative accuracy testing on the same schedule as source testing, instead of annually. For timeshared CEMS, they include: requiring a 15-minute sampling time for each timeshared engine; allowing unequal sample line lengths; reducing the minimum number of relative accuracy tests to five for each engine; reducing cylinder gas audits to quarterly; not requiring NO2 monitoring for rich-burn engines; allowing daily calibration error (CE) tests at the analyzer instead of at the probe tip, except for once per week (not requiring CEMS operation or calibration when there is a continuous record of engine non-operation.

Source Testing for Stationary Engines

The current requirement of subparagraph (f)(1)(C) is that emissions testing be done once every three years. The proposed amendments increase the frequency of source testing to every two years, or 8,760 operating hours, whichever occurs first. The testing frequency may be decreased to once every three years if an engine has not operated more than 2,000 hours since last source test.

In addition, the following source testing reforms are proposed:

- Emissions must be tested at for at least 15 minutes at peak load and for at least 30 minutes during normal operation. The source test can no longer be at one load under steady state conditions, unless that is the typical duty cycle. In addition NOx and CO must be tested for at least 15 minutes at actual peak load and actual minimum load. These two tests will not be required if the permit limits the engine to operating at one load.

- Pretests to determine if the engine needs repairs will not be allowed.
- The test must be conducted at least 40 operating hours or one week after any engine tuning or maintenance.
- If a test is started and shows non-compliance, it may not be aborted to allow engine tuning or repairs. The test must be completed and reported.
- A source testing contractor approved by SCAQMD must be used.
- A source test protocol must be submitted and approved by the District at least 60 days before the test is conducted. The protocol will also identify the critical parameters that will be measured during the test, as required by the Inspection and Maintenance Plan (discussed later). If longer than 60 days is needed to approve a protocol more time may be allowed to conduct test.
- SCAQMD must be notified of the test date.
- The test report must be submitted to SCAQMD within 60 days of the test date. This will assure that noncompliance will be reported.
- The operator must provide source testing facilities including sampling ports in the stack, safe sampling platforms, safe access to sampling platforms, and utilities for test equipment. Agricultural engines at remote locations that comply with California General Safety Orders are excused from this clause. Agricultural engines on wheels and moved to storage during the off-season are excused from this requirement.

<u>Inspection and Monitoring (I&M) Plan for Stationary Engines</u>

An I&M Plan will be added to the rule in subparagraph (f)(1)(D). Except for engines monitored by a CEMS, stationary engine operators will submit to SCAQMD for approval an I&M Plan application for each facility to assure continued compliance of the engines between source tests. The I&M Plan will include identification of engine and control equipment operating parameters necessary to maintain pollutant concentrations within the rule and permit limits. This will include:

- Procedures for using a portable NOx, CO and oxygen analyzer to establish the set points of the air-to-fuel ratio controller and loads;
- Procedures for verifying the AFRC is controlling the engine to the set point during the daily monitoring;
- Procedures for reestablishing all AFRC set points with a portable NOx, CO and oxygen analyzer;
- For engines with catalysts, maximum allowed exhaust temperature at the catalyst inlet per manufacturer specifications;
- For lean-burn engine with selective catalytic control devices, minimum exhaust temperature at the catalyst inlet for reactant flow and procedures for using portable NOx and oxygen analyzer to establish acceptable reactant flow rate as a function of load;
- Procedures for at least every 150 operating hours, emissions checks by a portable NOx, CO and oxygen (O2) analyzer. The schedule can be reduced to monthly, or every 750 operating hours if three consecutive weekly tests show compliance. If the monthly test

is non-compliant or for rich-burn engines with three-way catalyst the oxygen sensor is replaced, then weekly tests must be resumed. For diesel engines and other lean-burn engines that are subject to Regulation XX or have a NOx CEMS, the CO emission check will be quarterly or every 2000 engine operating hours. In order to be representative of actual operation, the test will be conducted at least 72 hours after any engine or control system maintenance or tuning. Within 48 hours of finding an operating parameter out-of-range an additional emission check will need to be conducted. The portable analyzer will be calibrated, maintained and operated in accordance with the manufacturer's specifications and recommendations and the SCAQMD's "Protocol for the Periodic Monitoring of Nitrogen Oxides, Carbon Monoxide, and Oxygen from Sources Subject to South Coast Air Quality Management District Rule 1110.2"

- Procedures for at least daily recordkeeping of monitoring data and actions required by the plan, including formats of the recordkeeping of engine load or flow rate, set points, and the maximum and acceptable ranges of parameters identified by clause (f)(1)(D)(i), elapsed time meter hours, and hours since last emission check required;
- For rich-burn engines with TWCs, the difference of the exhaust temperature at the inlet and outlet of the catalyst which can indicate changes in the effectiveness of the catalyst;

An I&M Plan will not be required for an engine if it is required by this rule to have a NOx and CO CEMS or voluntarily has a NOx and CO CEMS.

Operating Log

Because dual-fuel engines may consume both liquid and gaseous fuels, proposed paragraph (F)(1)(E) is proposed to require fuel use of both fuels to be logged, instead of either fuel.

New Non-Emergency Electrical Generating Engines

New monitoring procedures are required for the proposed emission standards for new, non-emergency, electrical generating engines. All such engines will be required to monitor: the net electrical output (MWe-hours) of the engine generator system, which is the difference between the electrical output of the generator and the electricity consumed by the auxiliary equipment necessary to operate the engine generator and heat recovery equipment; and the useful heat recovered (MWth-hours), which is the thermal energy recovered and put to an actual useful purpose.

Emissions in pounds per MWe-hour must be calculated based on CEMS data, source tests, and weekly emission checks. Mass emissions will be calculated using an F factor method from EPA 40 CFR 60, Appendix A, Method 19, or other approved method. Because Method 19 does not directly address VOC and CO, necessary conversion factors are provided in the rule. An annual report is required to verify compliance with the annual EEF.

Portable Analyzer Training

In order to assure that persons conducting the portable analyzer testing are properly trained to understand the equipment and the procedures for conducting testing, maintenance and calibration, subparagraph (f)(1)(G) requires persons to take a District-approved training program and obtain a certification issued by the District. SCAQMD intends to conduct the training.

Reporting noncompliance to the Executive Officer

If an engine owner/operator finds an engine to be operating outside the acceptable range for control equipment parameters, engine operating parameters, engine exhaust NOx, CO, VOC or oxygen concentrations, the owner/operator will: report the noncompliance within one hour in the same manner required by paragraph (b)(1) of Rule 430 – Breakdowns; immediately correct the noncompliance or shut down the engine within 24 hours or the end of an operating cycle, in the same manner as required by subparagraph (b)(3)(iv) of Rule 430; and comply with all requirements of Rule 430 if there was a breakdown.

Within seven calendar days after reported noncompliance has been corrected, but no later than thirty days from initial noncompliance date, operators will be required to submit a written noncompliance report which includes:

- Identification of equipment
- Duration of noncompliance
- Date of correction and information demonstrating compliance was achieved
- Types of excess emissions
- Quantification of excess emissions
- Determination of noncompliance as a result of operator error, neglect or improper operation or maintenance
- Verification that steps were immediately taken to correct noncompliance
- Description of corrective measures undertaken and/or to be undertaken to avoid similar noncompliance
- Photos or images of equipment which failed, if available

The rule provides a 72 hour window in which to report any engine or control system parameter which goes out of the acceptable range established by the Inspection and Monitoring plan or permit condition. In case of emergencies that prevent reporting all required information within the 72 hour limit, an allowance may be granted to extend the time of reporting.

Exemptions

Emergency, Flood Control and Fire Fighting Engines

The current rule exempts several types of engines from the subdivision (d) emission limits. Paragraph (h)(2) exempts emergency engines while paragraph (h)(3) exempts fire fighting and flood control engines. The proposed amendments do the following: combine the exemptions into paragraph (h)(2); require all of these engines to operate less than 200 hours per year; and require that permits conditions specifically limit the annual operating hours. This exemption also applies to agricultural emergency standby engines that are exempt from permit and operate 200 hours or less per year.

Start up Exemption

The current rule has no exemption during engine startups, after an engine overhaul or major repair requiring removal of a cylinder head or initial commissioning of new engine. The proposed amendments in paragraphs (h)(10),(11) and (12) will provide an exemption from:

- Startups for complying with the emission limits in the rule until emission controls reach operating temperature, but not longer than 30 minutes. AQMD may approve a longer period and make it a condition of the permit to operate;
- After an engine overhaul or major repair for a period not to exceed four operating hours;
- Initial commissioning of new engine for a period specified by permit conditions up to a maximum of 150 operating hours.

CONTROL TECHNOLOGIES

Although Rule 1110.2 controls emissions from both liquid-fueled (e.g., gasoline and diesel) and gaseous-fueled (e.g., natural gas, biogas, etc.) ICEs, the majority of engines expected to be affected by PAR 1110.2 are gaseous-fueled ICEs. Control technologies that are anticipated to be used to comply with PAR 1110.2 are described relative to the gaseous fuel used by the ICE. For the purposes of this discussion and the analysis in Chapter 4, the two primary fuel types under consideration are non-biogas and biogas. Non-biogas refers to natural gas, which is a gaseous fossil fuel consisting primarily of methane, but also includes significant quantities of ethane, butane, propane, carbon dioxide, nitrogen, helium and hydrogen sulfide. Biogas typically refers to a (biofuel) gas produced by the anaerobic digestion or fermentation of organic matter including manure, sewage sludge, municipal solid waste, biodegradable waste or any other biodegradable feedstock, under anaerobic conditions. Biogas is comprised primarily of methane and carbon dioxide. In most cases, biogas from landfills and sewage treatment contains siloxanes. The following subsections summarize the various types of control technologies expected to be used to comply with PAR 1110.2, divided into the two main categories of non-biogas and biogas engines.

Non-Biogas Engines – Retrofit Technologies

To comply with PAR 1110.2 the following control technologies are expected to be used by operators of non-biogas engines: oxidation catalyst, selective catalytic reduction or improved non-selective catalytic reduction. These control technologies are summarized in the following subsections.

Oxidation Catalyst

To meet the compliance limits of PAR 1110.2, SCAQMD staff expects that operators of non-biogas, RECLAIM, lean-burn engines that were not subject to BACT to install oxidation catalysts. Oxidation catalysts have two simultaneous tasks: 1) oxidation of carbon monoxide to carbon dioxide ($2CO + O2 \rightarrow 2CO2$) and 2) oxidation of unburned hydrocarbons (unburned and partially-burned fuel) to carbon dioxide and water ($2CxHy + (2x+y/2)O2 \rightarrow 2xCO2 + yH2O$). An oxidation catalyst contains materials (generally precious metals such as platinum or palladium) that promote oxidation reactions between oxygen, CO, and VOC to produce carbon dioxide and water vapor. These reactions occur when exhaust at the proper temperature and containing sufficient oxygen passes through the catalyst. Depending on the catalyst formulation, an oxidation catalyst may obtain reductions at temperatures as low as 300 or 400^{o}F, although minimum temperatures in the 600 to 700^{o}F range are generally required to achieve maximum reductions. The catalyst will maintain adequate performance at temperatures typically as high as 1350^{o}F before problems with physical degradation of the catalyst occur. In the case of rich-burn engines, where the exhaust does not contain enough oxygen to fully oxidize the CO and VOC in the exhaust, air can be injected into the exhaust upstream of the catalyst.

This type of catalytic converter is widely used on lean-burn engines to reduce hydrocarbon and carbon monoxide emissions.

The oxidation catalyst is a corrugated base metal substrate with an alumina wash coat loaded with precious metals such as platinum. The alumina is porous allowing for large surface areas to promote oxidation of any unreacted CO and hydrocarbons with oxygen remaining in the exhaust gas. Most oxidation catalysts can be retrofitted onto the engine without disruption of the existing design configuration.

Selective Catalytic Reduction

Selective catalytic reduction (SCR) is a post-combustion control equipment that is considered to be BACT for new equipment and BARCT for existing equipment. SCR can be used, if cost-effective, for NOx control of combustion sources like engines, boilers, process heaters, and gas turbines and it is capable of reducing NOx emissions by as much as 90 percent or higher. A typical SCR system design consists of an ammonia or urea reductant storage tank, ammonia vaporization and injection equipment, an SCR reactor with catalyst, an exhaust stack plus ancillary electronic instrumentation and operations control equipment. The way an SCR system reduces NOx is by a matrix of nozzles injecting a mixture of reductant and air into the flue gas exhaust stream from the combustion equipment. As this mixture flows into the SCR reactor with catalyst, the catalyst, reductant, and oxygen in the flue gas exhaust react primarily (i.e., selectively) with NO and NO2 to form nitrogen and water. The amount of reductant introduced into the SCR system is approximately a one-to-one molar ratio of reductant to NOx for optimum control efficiency, though the ratio may vary based on equipment-specific NOx reduction requirements. There are two main types of catalyst structures: the first type is one in which the catalyst is coated onto a metal structure and the second type is one with a ceramic-based catalyst onto which the catalyst components are calcified. Commercial catalysts used in SCRs are available in two forms: 1) solid, block configurations or 2) modules, plate or honeycomb type. Catalysts are comprised of a base material of titanium dioxide (TiO2) that is coated with either tungsten trioxide (WO3), molybdic anhydride (MoO3), vanadium pentoxide (V2O5), or iron oxide (Fe2O3). These materials are used for SCRs because of their high activity, insensitivity to sulfur in the exhaust, and useful life span of approximately five years. Ultimately, the material composition of the catalyst is dependent upon the application and flue gas conditions such as gas composition, temperature, et cetera.

For conventional SCRs, the minimum temperature for NOx reduction is 500 degrees Fahrenheit (^{o}F) and the maximum operating temperature for the catalyst is 800 ^{o}F. Zeolite SCR catalysts have a higher temperature operating range. Depending on the application, the type of fuel combusted, and the presence of sulfur compounds in the exhaust gas, the optimum flue gas temperature of an SCR system is case-by-case and will range between

550°F and 750°F to limit the occurrence of several undesirable side reactions at certain conditions. One of the major concerns associated with SCRs is the oxidation of sulfur dioxide (SO2) in the exhaust gas to sulfur trioxide (SO3) and the subsequent reaction between SO3 and ammonia to form secondary particulates such as ammonium bisulfate or ammonium sulfate. The formation of either ammonium bisulfate or ammonium sulfate depends on the amount of SO3 and ammonia present in the flue gas and can cause equipment plugging downstream of the catalyst. The presence of particulates, heavy metals and silica in the flue gas exhaust can also limit catalyst performance. The production of secondary particulates can be substantially minimized by reducing the quantity of injected ammonia, maintaining the exhaust temperature within a predetermined range, and maintaining a precise NOx to ammonia molar ratio to minimize the production of unreacted ammonia which is commonly referred to as 'ammonia slip.' Depending on the type of combustion equipment utilizing SCR technology, the typical amount of ammonia slip is typically zero to five ppm.

Lean-burn engines can use SCR to control NOx. All lean-burn, non-biogas engines are controlled with the exception of RECLAIM engines, which are exempt from the NOx limited Rule 1110.2.

Selective Non-catalytic Reduction

Selective non-catalytic reduction (SNCR) is another post-combustion control technique used to reduce the quantity of NOx in the flue gas by injecting ammonia or urea. The main differences between SNCR and SCR is that the SNCR reaction between ammonia and NOx in the hot flue gas occurs without the need for a catalyst and at much higher temperatures (i.e., between 1,200°F to 2,000°F). The SNCR reaction is also affected by the short residence time of ammonia and the molar ratio between ammonia and the initial quantities of NOx such that small quantities of unreacted ammonia remains (i.e., ammonia slip) and is subsequently released in the flue gas. With a control efficiency ranging between 50 and 85 percent, SNCR does not achieve as great of NOx emission reductions as SCR. Therefore, SNCR would not be considered equivalent to BARCT unless combined with other NOx control technologies.

Three-way Catalyst

Three-way catalysts reduce NOx in addition to oxidizing carbon monoxide and unburned hydrocarbons. The oxidation process is described above under the subheading oxidation catalysts. Reduction of NOx emissions requires an additional step. Platinum catalysis can be used to reduce NOx emissions. The NSCR catalyst promotes the chemical reduction of NOx in the presence of CO and VOC to produce oxygen and nitrogen. The three-way NSCR catalyst also contains materials that promote the oxidation of VOC and CO to form carbon dioxide and water vapor. To control NOx, CO, and VOC simultaneously, 3-way catalysts must operate in a narrow air/fuel ratio band (15.9 to 16.1 for natural gas-fired engines) that is close to stoichiometric. An electronic controller, which includes an oxygen sensor and feedback mechanism, is often necessary to maintain the air/fuel ratio in this narrow band. At this air/fuel ratio, the oxygen concentration in the exhaust is low, while concentrations of VOC and CO are not excessive.

The core, or substrate in modern catalytic converters is most often a ceramic honeycomb, however stainless steel foil honeycombs are also used. The purpose of the core is to "support the catalyst" and therefore it is often called a "catalyst support". In an effort to make converters more efficient, a washcoat is utilized, most often a mixture of silica and alumina. The washcoat, when added to the core, forms a rough, irregular surface which has a far greater surface area than the flat core surfaces, which is desirable to give the converter core a larger surface area and, therefore, more places for active precious metal sites. The catalyst is added to the washcoat (in suspension) before application to the core. The catalyst itself is most often a precious metal. Platinum is the most active catalyst and is widely used. However, it is not suitable for all applications because of unwanted additional reactions and/or cost. Palladium and rhodium are two other precious metals that are used. Platinum and rhodium are used as a reduction catalyst, while platinum and palladium are used as an oxidization catalyst.

Non-Biogas Engines – Replacement Technologies

The cost of compliance (CEMS, I&M, add-on control technology, etc.) may make it less costly to remove the existing non-biogas ICEs and replace them with other technologies, primarily electric motors. Replacing ICEs with electric motors means they would no longer be subject to the requirements of PAR 1110.2. The follow briefly describes electric motors used as a non-biogas replacement technology.

Electric Motors

An electric motor converts electrical energy into mechanical energy. Most electric motors work by electromagnetism, but motors based on other electromechanical phenomena, such as electrostatic forces and the piezoelectric effect, also exist. The fundamental principle upon which electromagnetic motors are based is that there is a mechanical force on any current-carrying wire contained within a magnetic field. The force is described by the Lorentz force law and is perpendicular to both the wire and the magnetic field. Most magnetic motors are rotary, but linear motors also exist. In a rotary motor, the rotating part (usually on the inside) is called the rotor, and the stationary part is called the stator. The rotor rotates because the wires and magnetic field are arranged so that a torque is developed about the rotor's axis. The motor contains electromagnets that are wound on a frame. Though this frame is often called the armature, the term is often erroneously applied. Correctly, the armature is that part of the motor across which the input voltage is supplied. Depending upon the design of the machine, either the rotor or the stator can serve as the armature.

For some operators, removing the existing ICEs driving pumps or compressors and replacing them electric motors may less costly when compared to the cost of complying with PAR 1110.2, which may include the costs of installing CEMS, inspection and maintenance, installing add-on control technology, etc. For the same reason, operators of ICE electrical generators may choose to simply shut the ICE down and buy electricity from the grid to operate the motors. Operators who choose this option, however, may also need to install an emergency backup generator. In the analysis of impacts in Chapter 4 SCAQMD staff assumed that 40 percent of the affected facility operators would use their existing ICEs for emergency backup generators and 20 percent were assumed to use diesel-fueled emergency generators. The remaining 40 percent are not expected to need emergency generators. It is expected that this assumption is an over estimation since some facility operators would not require emergency generators.

Biogas Engines – Retrofit Technologies

Emissions control of biogas engines typically requires biogas pre-treatment systems (BPTS) to remove siloxanes that would inactivate the catalysts. Biogas engines are expected to use a biogas pre-treatment system (BPTS) with SCR and oxidation catalyst (see the description SCR and oxidation catalysts in the subsections under "Non-biogas Engines), or use technologies that do not require BPTS, such as NOxTech or the CL.AIR® system. The following subsections briefly describe the NOxTech and CL.AIR® emissions control technologies for biogas engines.

Biogas Pre-Treatment Systems (BPTS)

BPTSs are designed to remove siloxanes from biogas streams to prevent fouling of emissions control systems. Typically the system consists of a condenser followed by a vessel or vessels segmented with different layers of carbon or silica gel media. Each medium is designed to filter siloxane, H_2S and VOCs, respectively. The change-out time for the vessel or vessels is approximately every 60 to 90 days. Inlet and outlet samples are taken at specific intervals to determine vessel condition. Tests have indicated that the control efficiency of BPTS produces non-detect levels of siloxanes, i.e., in the 100 ppb range.

NOx Tech Emissions Control for Biogas

NOxTech is an emissions control system for diesel and biogas engines. Emissions of hydrocarbons, CO, soot, and NOx are reduced in a one-step process. Engine exhaust is preheated in annular heat exchange tubes in the NOxTech reactor. In the reaction chamber, injected fuel auto ignites in the preheated exhaust and self-sustains autocatalysis based on engine load and, with the injection of urea or ammonia, reduces NOx. NOxTech controls emissions auto catalytically by gas-phase reactions. The gas-phase autocatalysis is self-sustained by auto thermal combustion, so NOxTech is not affected by contaminants which poison, foul, and plug catalysts. Feedback from a NOx analyzer can trim chemical injection in combination with the feed forward control.

When temperature in the reaction chamber is controlled in the range of 1,400-1,550°F, criteria pollutants, including ammonia slip, are maintained to specified limits. Biogas is a suitable fuel for auto thermal combustion and NOxTech equipment limits the additional biogas consumption within five to 10 percent of the engine fuel rate. Heat recovery minimizes this fuel penalty.

CL.Air Exhaust Treatment System

The CL.Air® system is designed for the post-combustion treatment of engine exhaust pollutants. The system is based on a regenerative heat exchanger and consists of two thermal storage media, a reaction chamber and a switching unit. The exhaust gas flows from the engine at a temperature of approximately 986°F via the switching unit into the first medium, where it is heated to approximately 1,472°F. For startup, the entering flue gas is heated by electrical heating elements. In the reaction chamber, the exhaust gas reacts with the oxygen it contains, oxidizing carbon monoxide and HC to produce carbon dioxide and water.

The exhaust gas emits heat again as it passes through the second medium and at a temperature of 1,022°F to 1,058°F it reaches the switching unit, which directs it to the smokestack or a downstream waste heat boiler. After a flow period of two to three minutes the direction of flow is reversed, and the exhaust gas takes heat away from storage medium two and passes it on to storage medium one. In this manner, the energy requirement of the thermal reactor is minimized (i.e., no additional heating is required). The CL.Air® system is not typically subject to the fouling problems catalytic emission control systems would have.

Biogas Engines – Replacement Technologies

The cost of compliance (CEMS, I&M, add-on control technology, etc.) may make it less costly to remove the existing biogas ICEs and replace them with other technologies. These technologies include boilers, gas turbines, microturbines, fuel cells and biogas-to-LNG systems. Replacing ICEs with the technologies described below means they would no longer be subject to the requirements of PAR 1110.2, but may be subject to other source-specific rules or regulations such as Regulation XIII – New Source Review. The follow is a description of each replacement technology.

Boilers

Boilers are steel or cast-iron pressure vessels designed to transfer heat from the combustion of a fuel to water contained in the vessel to produce hot water or steam. The principle components of a boiler are a burner, a firebox, heat exchanger and a means of creating and directing gas flow though the unit. Landfill gas-fired boilers in the district produce steam that drive electrical generators.

Gas Turbines

Gas turbines convert energy stored in a fluid into mechanical energy by channeling the fluid through a system of stationary and moving vanes. The moving vanes are attached to a rotor to turn either a shaft, producing work output in the form of torque, or to generate velocity and pressure energy in a jet. Gas turbines can be used in combined-cycle cogeneration and simple-cycle arrangements. Combined cycle systems are typically used for very large systems and generally have higher capital costs than simple cycle gas turbines. Although combined cycle systems are more efficient, thus, generating lower emissions, to be conservative the analysis of impacts in Chapter 4 assumed that simple-cycle systems, not combined cycle systems, would be a possible replacement for existing biogas engines in response to PAR 1110.2.

The CEC states that gas turbines generate relatively low amounts of NOx and CO and are fairly efficient when compared to ICEs. The most common turbines at landfills in California are Solar Turbines rated from one to five megawatts. The benefits of installing gas turbines are their lower maintenance and lower emissions, but they require more up front capital costs.

Microturbines

Microturbines are small combustion turbines and are composed of a compressor, a combustor, a recuperator (some models), a turbine, a generator and an alternator. According to the CEC, microturbines are available in sizes between 30 and 150 kilowatts. The advantage of microturbines is their non-labor-intensive operation, although gas treatment systems with biogas are needed. Microturbines have reached commercial status at several biogas facilities in the district.

Fuel Cells

Fuel cells use an electrochemical process that uses a catalyst to react hydrogen and oxygen, which produces direct current (DC) electricity, heat, CO2 and water. According to the CEC, the two commercially available fuel cells for biogas application are molten carbonate fuel cells (MCFCs) and phosphoric acid fuel cells (PAFCs). Fuel cells consist of a fuel reformer to produce hydrogen from methane in biogas, fuel cell stack and inverter. Fuel cells generate negligible criteria pollutant emissions.

A BPTS is required to remove contaminants from biogas that would foul catalysts in the fuel reformer and stack. Fuel cells have high gas to energy conversion efficiencies, but have high capital cost. Since fuel cells generate negligible direct and indirect emissions, adverse environmental impacts were not analyzed further in this EA.

Biogas-to-Liquefied Natural Gas (LNG) Systems

Biogas-to-LNG systems convert biogas to LNG and CO2. LNG is created when natural gas is cooled to minus 260ºF, reducing six-hundred cubic feet of gas into one cubic foot of liquid methane. This process consists of several stages of compression and cooling. LNG plants would consist of a power generation building, programmable logic control/motor control center building, compress skids, refrigeration skids, liquefier skids, storage tanks and loading equipment. The plant is composed of vessels, compressors, pipes, valves, filters, coolers instruments and process components in six modules: purification, CO2 removal, refrigeration, liquefaction and post purification, instrument air, and controls. An LNG storage and dispensing system is needed to transfer LNG from the facility to trucks.

The LNG facility at the Frank R. Bowerman Landfill in Irvine, California was used as a basis for the analysis in this report.[10] The Bowerman facility uses ICEs to supply power to the LNG facility. Since LNG systems are assumed to replace existing ICEs at affected facilities, it was assumed that facility operators who choose to install LNG plants in place of existing ICEs would use electricity from the power grid. Since the LNG facility would require some energy in the form of heat, it was assumed that operators that replace existing ICEs at affected facilities would install boilers to generate heat for the facility.

[10] Prometheus Energy Company, Bowerman I Natural Gas Process Facility Project Description, prepared for SCAQMD, undated.

The Bowerman facility has a LNG storage tank that can store five days worth of LNG generated at the facility. Dr. John Barclay of Prometheus Energy has stated that typical design of LNG storage tanks includes a capacity of three days.[11]

[11] Phone conversation between Dr. John Barclay, Chief Technology Officer of Prometheus Energy Company and James Koizumi of SCAQMD, August 1, 2007.

CHAPTER 3

EXISTING SETTING

Introduction
Aesthetics
Air Quality
Hazards/Hazardous Material
Solid/Hazardous Waste

INTRODUCTION

In order to determine the significance of the impacts associated with a proposed project, it is necessary to evaluate the project's impacts against the backdrop of the environment as it exists at the time the notice of preparation is published. The CEQA Guidelines defines "environment" as "the physical conditions that exist within the area which will be affected by a proposed project including land, air, water, minerals, flora, fauna, ambient noise, and objects of historical or aesthetic significance" (CEQA Guidelines §15360; see also Public Resources Code §21060.5). Furthermore, a CEQA document must include a description of the physical environment in the vicinity of the project, as it exists at the time the notice of preparation is published, from both a local and regional perspective (CEQA Guidelines §15125). Therefore, the "environment" or "existing setting" against which a project's impacts are compared consists of the immediate, contemporaneous physical conditions at and around the project site (Remy, et al; 1996).

AESTHEICS

General Affected Facilities

ICEs are used for commercial and industrial applications. ICEs can be housed within buildings or placed outside. If placed within a building, the ICEs will have ducting to the outside of the building. Building and fire codes regulate the placement and height of the exhaust stack.

If placed outside ICEs may be placed within housing that protects the ICEs from weather and reduces noise or may be exposed to the elements. The majority of the ICE and related equipment with the exception of ducting is low in height and not visible to the surrounding area due to existing fencing along the property lines and existing structures currently within the facilities may buffer the view of such equipment.

Biogas Facilities

Digester Gas

Digester gas facilities are placed industrial areas and are typically visibly industrial. Storage tanks and piping may be visible from outside the property line. Depending on the placement of buildings and the size of the facility, the existing ICE system may or may not be visible from outside the property line.

Landfill Gas

Active landfills are placed in industrial areas and are typically visibly industrial. Earthmoving equipment, heavy duty diesel transfer and disposal trucks may be seen from outside the property line. Depending on the placement of buildings and the size of the facility, the existing ICE system may or may not be visible from outside the property line.

AIR QUALITY

It is the responsibility of the SCAQMD to ensure that state and federal ambient air quality standards are achieved and maintained in its geographical jurisdiction. Health-based air quality standards have been established by California and the federal government for the following criteria air pollutants: ozone, carbon monoxide (CO), nitrogen dioxide (NO2), particulate matter less than 10 microns (PM10), particulate matter less than 2.5 microns (PM2.5) sulfur dioxide (SO2) and lead. These standards were established to protect sensitive receptors with a margin of safety from adverse health impacts due to exposure to air pollution. The California standards are more stringent than the federal standards and in the case of PM10 and SO2, far more stringent. California has also established standards for sulfate, visibility, hydrogen sulfide, and vinyl chloride. The state and national ambient air quality standards for each of these pollutants and their effects on health are summarized in Table 3-1. The SCAQMD monitors levels of various criteria pollutants at 34 monitoring stations. The 2004 air quality data from SCAQMD's monitoring stations are presented in Table 3-2.

Table 3-1
State and Federal Ambient Air Quality Standards

AIR POLLUTANT	STATE STANDARD Concentration/ Averaging Time	FEDERAL PRIMARY STANDARD Concentration/ Averaging Time (>)	MOST RELEVANT EFFECTS
Ozone	0.09 ppm, 1-hour average > 0.07 ppm, 8-hr avg.>	0.08 ppm, 8-hour average	(a) Pulmonary function decrements and localized lung edema in humans and animals; (b) Risk to public health implied by alterations in pulmonary morphology and host defense in animals; (c) Increased mortality risk; (d) Risk to public health implied by altered connective tissue metabolism and altered pulmonary morphology in animals after long-term exposures and pulmonary function decrements in chronically exposed humans; (e) Vegetation damage; (f) Property damage
Carbon Monoxide	9.0 ppm, 8-hour average> 20 ppm, 1-hour average>	9 ppm, 8-hour average 35 ppm, 1-hour average	(a) Aggravation of angina pectoris and other aspects of coronary heart disease; (b) Decreased exercise tolerance in persons with peripheral vascular disease and lung disease; (c) Impairment of central nervous system functions; (d) Possible increased risk to fetuses
Nitrogen Dioxide	0.18 ppm, 1-hour average> 0.030 ppm, annual average>	0.053 ppm, annual average	(a) Potential to aggravate chronic respiratory disease and respiratory symptoms in sensitive groups; (b) Risk to public health implied by pulmonary and extra-pulmonary biochemical and cellular changes and pulmonary structural changes; (c) Contribution to atmospheric discoloration

Table 3-1 (Concluded)
State and Federal Ambient Air Quality Standards

AIR POLLUTANT	STATE STANDARD Concentration/ Averaging Time	FEDERAL PRIMARY STANDARD Concentration/ Averaging Time (>)	MOST RELEVANT EFFECTS
Sulfur Dioxide	0.04 ppm, 24-hour average> 0.25 ppm, 1-hour average>	0.03 ppm, annual average 0.14 ppm, 24-hour average	(a) Bronchoconstriction accompanied by symptoms which may include wheezing, shortness of breath and chest tightness, during exercise or physical activity in person with asthma
Suspended Particulate Matter (PM10)	20 µg/m^3, annual arithmetic mean > 50 µg/m^3, 24-hour average>	150 µg/m^3, 24-hour average	(a) Exacerbation of symptoms in sensitive patients with respiratory or cardiovascular disease; (b) Declines in pulmonary function growth in children; (c) Increased risk of premature death from heart or lung diseases in the elderly
Suspended Particulate Matter (PM2.5)	12 µg/m3, ann. arithmetic mean >	15 µg/m^3, annual arithmetic mean 35 µg/m^3, 24-hour average(1)	
Sulfates	25 µg/m^3, 24-hour average>=	--(2)	(a) Decrease in ventilatory function; (b) Aggravation of asthmatic symptoms; (c) Aggravation of cardio-pulmonary disease; (d) Vegetation damage; (e) Degradation of visibility; (f) Property damage
Lead	1.5 µg/m^3, 30-day average>=	1.5 µg/m^3, calendar quarter	(a) Increased body burden; (b) Impairment of blood formation and nerve conduction
Visibility-Reducing Particles	In sufficient amount to give an extinction coefficient >0.23 km^{-1} (visual range less than 10 miles), with relative humidity <70%, 8-hour average (10am – 6pm, PST)	--(2)	Visibility impairment on days when relative humidity is less than 70 percent

ppm = parts per million

(1) The U.S. EPA lowered the PM2.5 24-hour average standard from 65µg/m^3 to 35µg/m^3 in September 2006. The 65µg/m^3 standard will be in effect until 2010.

(2) No federal standard established.

Table 3-2
2006 Air Quality Data – South Coast Air Quality Management District

CARBON MONOXIDE (CO)						
					No. Days Standard Exceeded[a]	
Source Receptor Area No.	Location of Air Monitoring Station	No. Days of Data	Max. Conc. (ppm, 1-hour)	Max. Conc. (ppm, 8-hour)	Federal ≥ 9.5 ppm, 8-hour	State > 9.0 ppm, 8-hour
LOS ANGELES COUNTY (Co)						
1	Central Los Angeles	362	3	2.6	0	0
2	Northwest Coast Los Angeles Co	365	3	2.0	0	0
3	Southwest Coast Los Angeles Co	363	3	2.3	0	0
4	South Coastal Los Angeles Co1	360	4	3.4	0	0
4	South Coastal Los Angeles Co2	--	--	--	--	--
6	West San Fernando Valley	365	5	3.4	0	0
7	East San Fernando Valley	365	4	3.5	0	0
8	West San Gabriel Valley	360	4	2.8	0	0
9	East San Gabriel Valley 1	365	2	1.7	0	0
9	East San Gabriel Valley 2	363	2	2.0	0	0
10	Pomona/Walnut Valley	365	3	2.1	0	0
11	South San Gabriel Valley	232*	3*	2.7*	0*	0*
12	South Central LA County	365	8	6.4	0	0
13	Santa Clarita Valley	363	2	1.3	0	0
ORANGE COUNTY						
16	North Orange County	362	6	3.0	0	0
17	Central Orange County	365	5	3.0	0	0
18	North Coastal Orange County	365	4	3.0	0	0
19	Saddleback Valley	365	2	1.8	0	0
RIVERSIDE COUNTY						
22	Norco/Corona	--	--	--	--	--
23	Metropolitan Riverside County 1	365	3	2.1	0	0
23	Metropolitan Riverside County 2	365	4	2.3	0	0
23	Mira Loma	364	4	2.7	0	0
24	Perris Valley	--	--	--	--	--
25	Lake Elsinore	362	1	1.0	0	0
29	Banning Airport	--	--	--	--	--
30	Coachella Valley 1**	365	2	1.0	0	0
30	Coachella Valley 2**	--	--	--	--	--
SAN BERNARDINO COUNTY						
32	NW San Bernardino Valley	360	3	1.8	0	0
33	SW San Bernardino Valley	--	--	--	--	--
34	Central San Bernardino Valley 1	365	3	2.0	0	0
34	Central San Bernardino Valley 2	364	3	2.3	0	0
35	East San Bernardino Valley	--	--	--	--	--
37	Central San Bernardino Mountains	--	--	--	--	--
38	East San Bernardino Mountains	--	--	--	--	--
	DISTRICT MAXIMUM		8	6.4	0	0
	SOUTH COAST AIR BASIN		8	6.4	0	0

KEY:

ppm = parts per million parts of air, by volume	* Less than 12 full months of data. May not be representative.
-- = Pollutant not monitored	** Salton Sea Air Basin

a) The federal 8-hour standard (8-hour average CO > 9 ppm) and state 8-hour standard (8-hour average CO > 9.0 ppm) were not exceeded. The federal and state 1-hour standards (35ppm and 20 ppm) were not exceeded, either.

Table 3-2 (Continued)
2006 Air Quality Data – South Coast Air Quality Management District

OZONE (O_3)										
							No. Days Standard Exceeded			
							Federal [b]		State [c]	
Source Rec. Area No.	Location of Air Monitoring Station	No. Days of Data	Max. Conc. (ppm, 1-hr)	Max. Conc. (ppm, 8-hr)	Fourth Highest Conc. (ppm, 8-hr)	Health Advisory ≥ 0.15 ppm, 1-hr	> 0.12 ppm, 1-hr	> 0.08 ppm, 8-hr	> 0.09 ppm, 1-hr	> 0.07 ppm, 1-hr
LOS ANGELES (LA) COUNTY (Co)										
1	Central LA	362	0.11	0.079	0.077	0	0	0	8	4
2	NW Coastal LA Co	365	0.10	0.074	0.069	0	0	0	3	0
3	SW Coastal LA Co	360	0.08	0.066	0.062	0	0	0	0	0
4	South Coastal LA Co1	364	0.08	0.058	0.058	0	0	0	0	0
4	South Coastal LA Co2	--	--	--	--	--	--	--	--	--
6	West San Fernando V	361	0.16	0.108	0.105	1	6	17	32	39
7	East San Fernando V	365	0.17	0.128	0.099	2	6	12	25	23
8	W San Gabriel Valley	365	0.15	0.117	0.095	1	5	7	25	24
9	E San Gabriel Valley 1	364	0.17	0.120	0.091	2	7	10	23	19
9	E San Gabriel Valley 2	363	0.18	0.128	0.107	2	10	15	37	31
10	Pomona/Walnut Valley	365	0.15	0.128	0.109	2	9	16	32	30
11	S San Gabriel Valley	250*	0.13*	0.095*	0.080*	0*	1*	3*	9*	5*
12	South Central LA Co	365	0.09	0.066	0.064	0	0	0	0	0
13	Santa Clarita Valley	359	0.16	0.120	0.112	1	20	40	62	64
ORANGE (OR) COUNTY (Co)										
16	North Orange Co	362	0.15	0.114	0.092	1	3	4	8	9
17	Central Orange Co	365	0.11	0.088	0.072	0	0	1	5	3
18	North Coastal OR Co	365	0.07	0.064	0.062	0	0	0	0	0
19	Saddleback Valley	356	0.12	0.105	0.092	0	0	6	13	17
RIVERSIDE (RV) COUNTY (Co)										
22	Norco/Corona	--	--	--	--	--	--	--	--	--
23	Metropolitan RV Co 1	365	0.15	0.116	0.113	1	8	30	45	59
23	Metropolitan RV Co 2	--	--	--	--	--	--	--	--	--
23	Mira Loma	364	0.16	0.119	0.107	1	4	25	39	48
24	Perris Valley	351	0.17	0.122	0.114	3	12	53	76	84
25	Lake Elsinore	362	0.14	0.109	0.102	0	3	24	40	58
29	Banning Airport	357	0.14	0.115	0.104	0	8	44	57	78
30	Coachella Valley 1**	361	0.13	0.109	0.101	0	2	23	37	67
30	Coachella Valley 2**	364	0.10	0.089	0.087	0	0	7	4	29
SAN BERNARDINO (SB) COUNTY										
32	Northwest SB Valley	365	0.17	0.130	0.114	2	14	25	50	54
33	Southwest SB Valley	--	--	--	--	--	--	--	--	--
34	Central SB Valley 1	361	0.16	0.123	0.116	1	12	29	47	49
34	Central SB Valley 2	362	0.15	0.127	0.119	3	10	29	52	57
35	East SB Valley	365	0.16	0.135	0.125	5	11	36	60	64
37	Central SB Mountains	365	0.16	0.142	0.112	2	9	59	71	96
38	East SB Mountains	--	--	--	--	--	--	--	--	--
DISTRICT MAXIMUM			0.18	0.142	0.125	5	20	59	76	96
SOUTH COAST AIR BASIN			0.18	0.142	0.125	10	35	86	102	121

KEY:

ppm = parts per million parts of air, by volume	* Less than 12 full months of data. May not be representative.
-- - Pollutant not monitored	** Salton Sea Air Basin

b) The federal 1-hour ozone standard was revoked and replaced by the 8-hour average ozone standard effective June 15, 2005. The 8-hour average California ozone standard of 0.07 ppm was established effective May 17, 2006.

c) The state standard is 1-hour average NO_2 > 0.25 ppm. The federal standard is annual arithmetic mean NO_2 > 0.0534 ppm. Air Resources Board has approved to lower the NO_2 1-hour standard to 0.18 ppm and establish a new annual standard of 0.030 ppm. The revisions are expected to become effective later in 2007.

Table 3-2 (Continued)
2006 Air Quality Data – South Coast Air Quality Management District

NITROGEN DIOXIDE (NO_2)				
Source Receptor Area No.	Location of Air Monitoring Station	No. Days of Data	Max. Conc. (ppm, 1-hour[d])	Annual Average[d] AAM Conc. (ppm)
LOS ANGELES COUNTY				
1	Central Los Angeles	360	0.11	0.0288
2	Northwest Coastal Los Angeles Co	365	0.08	0.0173
3	Southwest Coastal Los Angeles Co	351	0.10	0.0155
4	South Coastal Los Angeles Co1	357	0.10	0.0215
4	South Coastal Los Angeles Co2	--	--	--
6	West San Fernando Valley	363	0.07	0.0174
7	East San Fernando Valley	365	0.10	0.0274
8	West San Gabriel Valley	365	0.12	0.0245
9	East San Gabriel Valley 1	365	0.11	0.0258
9	East San Gabriel Valley 2	362	0.10	0.0206
10	Pomona/Walnut Valley	365	0.10	0.0307
11	South San Gabriel Valley	204*	0.10*	0.0283*
12	South Central LA County	363	0.14	0.0306
13	Santa Clarita Valley	359	0.08	0.0184
ORANGE COUNTY				
16	North Orange County	361	0.09	0.0224
17	Central Orange County	343	0.11	0.0197
18	North Coastal Orange County	361	0.10	0.0145
19	Saddleback Valley	--	--	--
RIVERSIDE COUNTY				
22	Norco/Corona	--	--	--
23	Metropolitan Riverside County 1	365	0.08	0.0199
23	Metropolitan Riverside County 2	--	--	--
23	Mira Loma	332	0.08	0.0194
24	Perris Valley	--	--	--
25	Lake Elsinore	352	0.07	0.0151
29	Banning Airport	355	0.11	0.0161
30	Coachella Valley 1**	359	0.09	0.0103
30	Coachella Valley 2**	--	--	--
SAN BERNARDINO COUNTY				
32	Northwest SB Valley	337	0.10	0.0310
33	Southwest SB Valley	--	--	--
34	Central SB Valley 1	362	0.09	0.0270
34	Central SB Valley 2	362	0.09	0.0252
35	East SB Valley	--	--	--
37	Central SB Mountains	--	--	--
38	East SB Mountains	--	--	--
	DISTRICT MAXIMUM		0.14	0.0310
	SOUTH COAST AIR BASIN		0.14	0.0310

KEY:

ppm = parts per million parts of air, by volume	* Less than 12 full months of data. May not be representative.
AAM = Annual Arithmetic Mean	** Salton Sea Air Basin
-- = Pollutant not monitored	

d) The state standards are 1-hour average SO_2 > 0.25 ppm and 24-hour average SO_2 > 0.04 ppm. The federal standards are annual arithmetic mean SO_2 > 0.03 ppm, 24-hour average > 0.14 ppm, and 3-hour average > 0.50 ppm. The federal and state SO_2 standards were not exceeded.

Table 3-2 (Continued)
2006 Air Quality Data – South Coast Air Quality Management District

SULFUR DIOXIDE (SO_2)				
Source Receptor Area No.	Location of Air Monitoring Station	No. Days of Data	Maximum Concentration[e)] (ppm, 1-hour)	Maximum Concentration[e)] (ppm, 24-hour)
LOS ANGELES COUNTY				
1	Central Los Angeles	365	0.03	0.006
2	Northwest Coast Los Angeles County	--	--	--
3	Southwest Coast Los Angeles County	363	0.02	0.006
4	South Coastal Los Angeles County 1	364	0.03	0.010
4	South Coastal Los Angeles County 2	--	--	--
6	West San Fernando Valley	--	--	--
7	East San Fernando Valley	360	0.01	0.004
8	West San Gabriel Valley	--	--	--
9	East San Gabriel Valley 1	--	--	--
9	East San Gabriel Valley 2	--	--	--
10	Pomona/Walnut Valley	--	--	--
11	South San Gabriel Valley	--	--	--
12	South Central LA County	--	--	--
13	Santa Clarita Valley	--	--	--
ORANGE COUNTY				
16	North Orange County	--	--	--
17	Central Orange County	--	--	--
18	North Coastal Orange County	353	0.01	0.004
19	Saddleback Valley	--	--	--
RIVERSIDE COUNTY				
22	Norco/Corona	--	--	--
23	Metropolitan Riverside County 1	365	0.01	0.004
23	Metropolitan Riverside County 2	--	--	--
23	Mira Loma	--	--	--
24	Perris Valley	--	--	--
25	Lake Elsinore	--	--	--
29	Banning Airport	--	--	--
30	Coachella Valley 1**	--	--	--
30	Coachella Valley 2**	--	--	--
SAN BERNARDINO COUNTY				
32	Northwest San Bernardino Valley	--	--	--
33	Southwest San Bernardino Valley	--	--	--
34	Central San Bernardino Valley 1	365	0.01	0.003
34	Central San Bernardino Valley 2	--	--	--
35	East San Bernardino Valley	--	--	--
37	Central San Bernardino Mountains	--	--	--
38	East San Bernardino Mountains	--	--	--
	DISTRICT MAXIMUM		0.03	0.010
	SOUTH COAST AIR BASIN		0.03	0.010

KEY:

ppm = parts per million parts of air, by volume	* Less than 12 full months of data. May not be representative.
-- = Pollutant not monitored	** Salton Sea Air Basin

e) PM10 samples were collected every 6 days at all sites except for Station Number 4144 and 4157 where samples were collected every 3 days.

Table 3-2 (Continued)
2006 Air Quality Data – South Coast Air Quality Management District

SUSPENDED PARTICULATE MATTER PM10 f),						
				No. (%) Samples Exceeding Standard		
Source Receptor Area No.	Location of Air Monitoring Station	No. Days of Data	Max. Conc. (µg/m³, 24-hour)	Federal > 150 µg/m³, 24-hour	State > 50 µg/m³, 24-hour	Annual Average[i] AAM Conc. (µg/m³)
LOS ANGELES COUNTY (Co)						
1	Central Los Angeles	59	59	0	3(5.1)	30.3
2	NW Coastal Los Angeles County	--	--	--	--	--
3	SW Coast Los Angeles County2	51	45	0	0	26.5
4	South Coastal Los Angeles County1	61	78	0	6(9.8)	31.1
4	South Coastal Los Angeles County2	58	117	0	19(32.7)	45.0
6	West San Fernando Valley	--	--	--	--	--
7	East San Fernando Valley	54	71	0	10(18.5)	35.6
8	West San Fernando Valley	--	--	--	--	--
9	East San Gabriel Valley 1	58	81	0	7(12.1)	31.9
9	East San Gabriel Valley 2	--	--	--	--	--
10	Pomona/Walnut Valley	--	--	--	--	--
11	South San Gabriel Valley	--	--	--	--	--
12	South Central LA County	--	--	--	--	--
13	Santa Clarita Valley	58	53	0	1(1.7)	23.4
ORANGE COUNTY						
16	North Orange County	--	--	--	--	--
17	Central Orange County	56	104	0	7(12.5)	33.4
18	North Coastal Orange County	--	--	--	--	--
19	Saddleback Valley	50	57	0	1(2.0)	22.8
RIVERSIDE COUNTY						
22	Norco/Corona	57	74	0	10(17.5)	36.5
23	Metropolitan Riverside County 1	118	109	0	71(60.2)	54.4
23	Metropolitan Riverside County 2	--	--	--	--	--
23	Mira Loma	59	124	0	41(69.5)	64.0
24	Perris Valley	54	125	0	19(35.2)	45.0
25	Lake Elsinore	--	--	--	--	--
29	Banning Airport	55	75	0	8(14.6)	31.1
30	Coachella Valley 1**	57	73+	0+	2(3.5)+	24.5+
30	Coachella Valley 2**	115	122+	0+	57(49.6)+	52.7+
SAN BERNARDINO COUNTY-						
32	NW San Bernardino Valley	--	--	--	--	--
33	SW San Bernardino Valley	62	78	0	17(27.4)	42.3
34	Central San Bernardino Valley 1	60	142	0	31(51.7)	53.5
34	Central San Bernardino Valley 2	57	92	0	24(42.1)	46.0
35	East San Bernardino Valley	60	103	0	12(20.0)	36.2
37	Central San Bernardino Mountains	58	63	0	1(1.7)	26.2
38	East San Bernardino Mountains	--	--	--	--	--
	DISTRICT MAXIMUM		142+	0+	71	64.0
	SOUTH COAST AIR BASIN		142+	0+	75	64.0

KEY:

µg/m³ = micrograms per cubic meter of air	-- = Pollutant not monitored
AAM = Annual Arithmetic Mean	** Salton Sea Air Basin

f) PM2.5 samples were collected every 3 days at all sites except for the following sites: Station Numbers 060, 072, 077, 087, 3176, and 4144 where samples were taken every day, and Station Number 5818 where samples were taken every 6 days.

i) U.S. EPA has revised the federal 24-hour PM2.5 standard from 65 µg/m³ to 35 µg/m³; effective December 17, 2006.

Table 3-2 (Continued)
2006 Air Quality Data – South Coast Air Quality Management District

SUSPENDED PARTICULATE MATTER PM2.5 [g]						
					No. (%) Samples Exceeding Standard	Annual Averages[j]
Source Receptor Area No.	Location of Air Monitoring Station	No. Days of Data	Max. Conc. (µg/m^3, 24-hour)	98th Percentile Conc. in µg/m3 24-hr	Federal > 65 µg/m^3, 24-hour	AAM Conc. (µg/m^3)
LOS ANGELES COUNTY						
1	Central Los Angeles	330	56.2	38.9	0	15.6
2	Northwest Coastal Los Angeles Co	--	--	--	--	--
3	Southwest Coastal Los Angeles Co 2	--	--	--	--	--
4	South Coastal Los Angeles Co 1	290*	58.5*	34.9*	0*	14.2*
4	South Coastal Los Angeles County 2	320	53.6	35.3	0	14.5
6	West San Fernando Valley	92	44.1	32.0	0	12.9
7	East San Fernando Valley	104	50.7	43.4	0	16.6
8	West San Gabriel Valley	113	45.9	32.1	0	13.4
9	East San Gabriel Valley 1	278*	52.8*	38.5*	0*	15.5*
9	East San Gabriel Valley 2	--	--	--	--	--
10	Pomona/Walnut Valley	--	--	--	--	--
11	South San Gabriel Valley	116	72.2	43.1	1(0.9)	16.7
12	South Central LA County	107	55.0	44.5	0	16.7
13	Santa Clarita Valley	--	--	--	--	--
ORANGE COUNTY						
16	North Orange County	--	--	--	--	--
17	Central Orange County	330	56.2	40.5	0	14.1
18	North Coastal Orange County	--	--	--	--	--
19	Saddleback Valley	106	47.0	25.7	0	11.0
RIVERSIDE COUNTY						
22	Norco/Corona	--	--	--	--	--
23	Metropolitan Riverside County 1	300	68.5	53.7	1(0.3)	19.0
23	Metropolitan Riverside County 2	105	55.3	47.7	0	17.0
23	Mira Loma	113	63.0	52.5	0	20.6
24	Perris Valley	--	--	--	--	--
25	Lake Elsinore	--	--	--	--	--
29	Banning Airport	--	--	--	--	--
30	Coachella Valley 1**	111	24.8	15.9	0	7.7
30	Coachella Valley 2**	107	24.3	19.1	0	9.5
SAN BERNARDINO COUNTY						
32	Northwest San Bernardino Valley	--	--	--	--	--
33	Southwest San Bernardino Valley	107	53.7	41.5	0	18.5
34	Central San Bernardino Valley1	112	52.6	43.8	0	17.6
34	Central San Bernardino Valley2	102	55.0	48.4	0	17.8
35	East San Bernardino Valley	--	--	--	--	--
37	Central San Bernardino Mountains	--	--	--	--	--
38	East San Bernardino Mountains	42*	40.1*	40.1*	0*	11.2*
DISTRICT MAXIMUM			72.2	53.7	1	20.6
SOUTH COAST AIR BASIN			72.2	53.7	1	20.6

KEY:

µg/m^3 = micrograms per cubic meter of air	-- = Pollutant not monitored
AAM = Annual Arithmetic Mean	** Salton Sea Air Basin

g) Total suspended particulates, lead, and sulfate were determined from samples collected every 6 days by the high volume sampler method, on glass fiber filter media.

j) Federal PM2.5 standard is annual average (AAM) > 15 µg/m^3. State standard is annual average (AAM) > 12 µg/m^3.

Table 3-2 (Continued)
2006 Air Quality Data – South Coast Air Quality Management District

TOTAL SUSPENDED PARTICULATES TSP h)				
Source Receptor Area No.	Location of Air Monitoring Station	No. Days of Data	Max. Conc. (µg/m^3, 24-hour)	Annual Average AAM Conc. (µg/m^3)
LOS ANGELES COUNTY (Co)				
1	Central Los Angeles	59	109	63.3
2	Northwest Coastal Los Angeles Co	56	76	40.2
3	Southwest Coast Los Angeles Co 2	56	84	43.1
4	South Coastal Los Angeles Co 1	62	157	62.9
4	South Coast Los Angeles Co 2	59	192	71.1
6	West San Fernando Valley	--	--	--
7	East San Fernando Valley	--	--	--
8	West San Gabriel Valley	60	123	42.8
9	East San Gabriel Valley 1	59	142	68.4
9	East San Gabriel Valley 2	--	--	--
10	Pomona/Walnut Valley	--	--	--
11	South San Gabriel Valley	58	768	79.3
12	South Central LA County	58	147	68.4
13	Santa Clarita Valley	--	--	--
ORANGE COUNTY				
16	North Orange County	--	--	--
17	Central Orange County	--	--	--
18	North Coastal Orange County	--	--	--
19	Saddleback Valley	--	--	--
RIVERSIDE COUNTY				
22	Norco/Corona	--	--	--
23	Metropolitan Riverside County 1	59	169	91.2
23	Metropolitan Riverside County 2	59	131	72.9
23	Mira Loma	--	--	--
24	Perris Valley	--	--	--
25	Lake Elsinore	--	--	--
29	Banning Airport	--	--	--
30	Coachella Valley 1**	--	--	--
30	Coachella Valley 2**	--	--	--
SAN BERNARDINO COUNTY				
32	NW San Bernardino Valley	58	105	54.6
33	SW San Bernardino Valley	--	--	--
34	Central San Bernardino Valley 1	59	190	101.0
34	Central San Bernardino Valley 2	54	174	87.0
35	East San Bernardino Valley	--	--	--
37	Central San Bernardino Mountains	--	--	--
38	East San Bernardino Mountains	--	--	--
	DISTRICT MAXIMUM		768	101.0
	SOUTH COAST AIR BASIN		768	101.0

KEY:

µg/m^3 = micrograms per cubic meter of air	-- = Pollutant not monitored
AAM = Annual Arithmetic Mean	** Salton Sea Air Basin

h) Federal annual PM10 standard (AAM > 50 µg/m^3) was revoked effective December 17, 2006. State standard is annual average (AAM) > 20 µg/m3.

Table 3-2 (Concluded)
2006 Air Quality Data – South Coast Air Quality Management District

		LEAD[h)]		SULFATES (SOx)[h)]	
Source Receptor Area No.	Location of Air Monitoring Station	Max. Monthly Average Conc[k)] (µg/m³)	Max. Quarterly Average Conc.[k)] (µg/m³)	Max. Conc. (µg/m³, 24-hour)	No. (%) Samples Exceeding State Standard ≥ 25 µg/m³, 24-hour
LOS ANGELES COUNTY (Co)					
1	Central Los Angeles	0.02	0.01	18.2	0
2	Northwest Coastal Los Angeles Co	--	--	12.2	0
3	Southwest Coastal Los Angeles Co 2	0.01	0.01	13.6	0
4	South Coastal Los Angeles Co 1	0.01	0.01	17.8	0
4	South Coastal Los Angeles Co 2	0.01	0.01	18.8	0
6	West San Fernando Valley	--	--	--	--
7	East San Fernando Valley	--	--	--	--
8	West San Gabriel Valley	--	--	28.7	1(1.7)
9	East San Gabriel Valley 1	--	--	20.8	0
9	East San Gabriel Valley 2	--	--	--	--
10	Pomona/Walnut Valley	--	--	--	--
11	South San Gabriel Valley	0.03	0.02	28.6	1(1.7)
12	South Central LA County	0.02	0.02	24.1	0
13	Santa Clarita Valley	--	--	--	--
ORANGE COUNTY					
16	North Orange County	--	--	--	--
17	Central Orange County	--	--	--	--
18	North Coastal Orange County	--	--	--	--
19	Saddleback Valley	--	--	--	--
RIVERSIDE COUNTY					
22	Norco/Corona	--	--	--	--
23	Metropolitan Riverside County 1	0.01	0.01	10.8	0
23	Metropolitan Riverside County 2	0.01	0.01	9.9	0
23	Mira Loma	--	--	--	--
24	Perris Valley	--	--	--	--
25	Lake Elsinore	--	--	--	--
29	Banning Airport	--	--	--	--
30	Coachella Valley 1**	--	--	--	--
30	Coachella Valley 2**	--	--	--	--
SAN BERNARDINO COUNTY					
32	NW San Bernardino Valley	0.01	0.01	9.1	0
33	SW San Bernardino Valley	--	--	--	--
34	Central San Bernardino Valley 1	--	--	10.3	0
34	Central San Bernardino Valley 2	0.02	0.01	11.0	0
35	East San Bernardino Valley	--	--	--	--
37	Central San Bernardino Mountains	--	--	--	--
38	East San Bernardino Mountains	--	--	--	--
DISTRICT MAXIMUM		0.03	0.02	28.7	1
SOUTH COAST AIR BASIN		0.03	0.02	28.7	1

KEY:

µg/m³ = micrograms per cubic meter of airF	** Salton Sea Air Basin
-- = Pollutant not monitored	

h) Federal annual PM10 standard (AAM > 50 µg/m³) was revoked effective December 17, 2006. State standard is annual average (AAM) > 20 µg/m3.

k) Federal lead standard is quarterly average > 1.5 µg/m3; and state standard is monthly average > µg/m3. No location exceeded lead standards.

Criteria Pollutants

Carbon Monoxide

CO is a colorless, odorless, relatively inert gas. It is a trace constituent in the unpolluted troposphere, and is produced by both natural processes and human activities. In remote areas far from human habitation, carbon monoxide occurs in the atmosphere at an average background concentration of 0.04 ppm, primarily as a result of natural processes such as forest fires and the oxidation of methane. Global atmospheric mixing of CO from urban and industrial sources creates higher background concentrations (up to 0.20 ppm) near urban areas. The major source of CO in urban areas is incomplete combustion of carbon-containing fuels, mainly gasoline. In 2002, approximately 98 percent of the CO emitted into the Basin's atmosphere was from mobile sources. Consequently, CO concentrations are generally highest in the vicinity of major concentrations of vehicular traffic.

CO is a primary pollutant, meaning that it is directly emitted into the air, not formed in the atmosphere by chemical reaction of precursors, as is the case with ozone and other secondary pollutants. Ambient concentrations of CO in the Basin exhibit large spatial and temporal variations due to variations in the rate at which CO is emitted and in the meteorological conditions that govern transport and dilution. Unlike ozone, CO tends to reach high concentrations in the fall and winter months. The highest concentrations frequently occur on weekdays at times consistent with rush hour traffic and late night during the coolest, most stable portion of the day.

Individuals with a deficient blood supply to the heart are the most susceptible to the adverse effects of CO exposure. The effects observed include earlier onset of chest pain with exercise, and electrocardiograph changes indicative of worsening oxygen supply to the heart.

Inhaled CO has no direct toxic effect on the lungs, but exerts its effect on tissues by interfering with oxygen transport by competing with oxygen to combine with hemoglobin present in the blood to form carboxyhemoglobin (COHb). Hence, conditions with an increased demand for oxygen supply can be adversely affected by exposure to CO. Individuals most at risk include patients with diseases involving heart and blood vessels, fetuses (unborn babies), and patients with chronic hypoxemia (oxygen deficiency) as seen in high altitudes.

Reductions in birth weight and impaired neurobehavioral development have been observed in animals chronically exposed to CO resulting in COHb levels similar to those observed in smokers. Recent studies have found increased risks for adverse birth outcomes with exposure to elevated CO levels. These include pre-term births and heart abnormalities.

Carbon monoxide concentrations were measured at 25 locations in the Basin and neighboring SSAB areas in 2006. Carbon monoxide concentrations did not exceed the standards in 2006. The highest eight-hour average carbon monoxide concentration recorded (6.4 ppm in the South Central Los Angeles County area) was 71 percent of the federal carbon monoxide standard. The maximum annual average nitrogen dioxide concentration (0.0310 ppm recorded in the Northwest San Bernardino Valley area) was 58 percent of the federal standard. Concentrations of the remaining pollutants remained well below the federal standards.

The 2003 AQMP revisions to the SCAQMD's CO Plan served two purposes: it replaced the 1997 attainment demonstration that lapsed at the end of 2000; and it provided the basis for a CO maintenance plan in the future. In 2004, the SCAQMD formally requested the U.S. EPA to re-designate the Basin from non-attainment to attainment with the CO National Ambient Air Quality Standards. On February 24, 2007, U.S. EPA published in the Federal Registrar its proposed decision to re-designate the Basin from non-attainment to attainment for CO. The comment period on the re-designation proposal closed on March 16, 2007 with no comments received by the U.S. EPA. On May 11, 2007, U.S. EPA published in the Federal Registrar its final decision to approve the SCAQMD's request for re-designation from non-attainment to attainment for CO, effective June 11, 2007.

Ozone

Ozone (O3), a colorless gas with a sharp odor, is a highly reactive form of oxygen. High ozone concentrations exist naturally in the stratosphere. Some mixing of stratospheric ozone downward through the troposphere to the earth's surface does occur; however, the extent of ozone transport is limited. At the earth's surface in sites remote from urban areas ozone concentrations are normally very low (0.03-0.05 ppm).

While ozone is beneficial in the stratosphere because it filters out skin-cancer-causing ultraviolet radiation, it is a highly reactive oxidant. It is this reactivity which accounts for its damaging effects on materials, plants, and human health at the earth's surface.

The propensity of ozone for reacting with organic materials causes it to be damaging to living cells and ambient ozone concentrations in the Basin are frequently sufficient to cause health effects. Ozone enters the human body primarily through the respiratory tract and causes respiratory irritation and discomfort, makes breathing more difficult during exercise, and reduces the respiratory system's ability to remove inhaled particles and fight infection.

Individuals exercising outdoors, children and people with preexisting lung disease, such as asthma and chronic pulmonary lung disease, are considered to be the most susceptible subgroups for ozone effects. Short-term exposures (lasting for a few hours) to ozone at levels typically observed in southern California can result in breathing pattern changes, reduction of breathing capacity, increased susceptibility to infections, inflammation of the lung tissue, and some immunological changes. In recent years, a correlation between elevated ambient ozone levels and increases in daily hospital admission rates, as well as mortality, has also been reported. An increased risk for asthma has been found in children who participate in multiple sports and live in high ozone communities. Elevated ozone levels are also associated with increased school absences.

Ozone exposure under exercising conditions is known to increase the severity of the abovementioned observed responses. Animal studies suggest that exposures to a combination of pollutants which include ozone may be more toxic than exposure to ozone alone. Although lung volume and resistance changes observed after a single exposure diminish with repeated exposures, biochemical and cellular changes appear to persist, which can lead to subsequent lung structural changes.

In 2006, the SCAQMD regularly monitored ozone concentrations at 29 locations in the Basin and SSAB. All areas monitored were below the stage 1 episode level (0.20 ppm), but the maximum concentrations in the Basin exceeded the health advisory level (0.15 ppm).

Maximum ozone concentrations in the SSAB areas monitored by the SCAQMD were lower than in the Basin and were below the health advisory level.

In 2006, the maximum ozone, PM10 and PM2.5 concentrations in the Basin continued to exceed federal standards by wide margins. Maximum one-hour and eight-hour average ozone concentrations were 0.18 ppm and 0.142 ppm (the one-hour was recorded in East San Gabriel Valley and the eight-hour was recorded in Central San Bernardino Mountains area). The eight-hour standard was 178 percent of the federal standards. The federal one-hour standard was revoked and replaced by the eight hour standard on June 15, 2005. Maximum 24-hour average and annual average PM10 concentrations were 142 $\mu g/m^3$ recorded in the South Coastal San Bernardino Valley area and 64.0 $\mu g/m^3$ recorded in the Mira Loma area. The 24-hour standard was 94 percent of the federal 24-hour. The federal annual average standards were revoked December 17, 2006. Maximum 24-hour average and annual average PM2.5 concentrations (72.2 $\mu g/m^3$ recorded in the South Central Los Angeles County area and 20.6 $\mu g/m^3$ recorded in the Mira Loma area) were 206 and 137 percent of the federal 24-hour (65 $\mu g/m^3$) and annual average standards, respectively.

In 1997, the USEPA promulgated a new 8-hour national ambient air quality standard for ozone. Soon thereafter, a court decision ordered that the USEPA could not enforce the new standard until adequate justification for the new standard was provided. The USEPA appealed the decision to the Supreme Court. On February 27, 2001, the Supreme Court upheld USEPA's authority and methods to establish clean air standards. The Supreme Court, however, ordered USEPA to revise its implementation plan for the new ozone standard. The EPA has since adopted the new 8-hour standard. Meanwhile, the California Air Resources Board (CARB) and local air districts continue to collect technical information in order to prepare for an eventual State Implementation Plan (SIP) to reduce unhealthful levels of ozone in areas violating the new federal standard. California has previously developed a SIP for the one-hour ozone standard, which has been approved by USEPA for the South Coast Air Basin.

The objective of the 2007 AQMP is to attain and maintain ambient air quality standards. Based upon the modeling analysis described in the Draft Program Environmental Impact Report for the 2007 AQMP implementation of all control measures contained in the 2007 AQMP is anticipated to bring the district into compliance with the federal eight-hour ozone standard by 2024 and the state eight-hour ozone standard beyond 2024.

Nitrogen Dioxide

NO2 is a reddish-brown gas with a bleach-like odor. Nitric oxide (NO) is a colorless gas, formed from the nitrogen (N2) and oxygen (O2) in air under conditions of high temperature and pressure which are generally present during combustion of fuels; NO reacts rapidly with the oxygen in air to form NO2. NO2 is responsible for the brownish tinge of polluted air. The two gases, NO and NO2, are referred to collectively as NOx. In the presence of sunlight, NO2 reacts to form nitric oxide and an oxygen atom. The oxygen atom can react further to form ozone, via a complex series of chemical reactions involving hydrocarbons. Nitrogen dioxide may also react to form nitric acid (HNO3) which reacts further to form nitrates, components of PM2.5 and PM10.

Population-based studies suggest that an increase in acute respiratory illness, including infections and respiratory symptoms in children (not infants), is associated with long-term exposures to NO2 at levels found in homes with gas stoves, which are higher than ambient levels found in southern California. Increase in resistance to air flow and airway contraction is observed after short-term exposure to NO2 in healthy subjects. Larger decreases in lung functions are observed in individuals with asthma and/or chronic obstructive pulmonary disease (e.g., chronic bronchitis, emphysema) than in healthy individuals, indicating a greater susceptibility of these sub-groups. More recent studies have found associations between NO2 exposures and cardiopulmonary mortality, decreased lung function, respiratory symptoms and emergency room asthma visits.

In animals, exposure to levels of NO2 considerably higher than ambient concentrations results in increased susceptibility to infections, possibly due to the observed changes in cells involved in maintaining immune functions. The severity of lung tissue damage associated with high levels of ozone exposure increases when animals are exposed to a combination of ozone and NO2.

In 2006, nitrogen dioxide concentrations were monitored at 24 locations. No area of the Basin or SSAB exceeded the federal or state standards for nitrogen dioxide. The Basin has not exceeded the federal standard for nitrogen dioxide (0.0534 ppm) since 1991, when the Los Angeles County portion of the Basin recorded the last exceedance of the standard in any U.S. county. The nitrogen dioxide state standard was not exceeded at any SCAQMD monitoring location in 2006. The highest one-hour average concentration recorded (0.14 ppm in South Central Los Angeles) was 56 percent of the state standard. NOx emission reductions continue to be necessary because it is a precursor to both ozone and PM (PM2.5 and PM10) concentrations.

Sulfur Dioxide

SO2 is a colorless gas with a sharp odor. It reacts in the air to form sulfuric acid (H2SO4), which contributes to acid precipitation, and sulfates, which are components of PM10 and PM2.5. Most of the SO2 emitted into the atmosphere is produced by burning sulfur-containing fuels.

Exposure of a few minutes to low levels of SO2 can result in airway constriction in some asthmatics. All asthmatics are sensitive to the effects of SO2. In asthmatics, increase in resistance to air flow, as well as reduction in breathing capacity leading to severe breathing difficulties, is observed after acute higher exposure to SO2. In contrast, healthy individuals do not exhibit similar acute responses even after exposure to higher concentrations of SO2.

Animal studies suggest that despite SO2 being a respiratory irritant, it does not cause substantial lung injury at ambient concentrations. However, very high levels of exposure can cause lung edema (fluid accumulation), lung tissue damage, and sloughing off of cells lining the respiratory tract.

Some population-based studies indicate that the mortality and morbidity effects associated with fine particles show a similar association with ambient SO2 levels. In these studies, efforts to separate the effects of SO2 from those of fine particles have not been successful. It is not clear whether the two pollutants act synergistically or one pollutant alone is the predominant factor.

No exceedances of federal or state standards for sulfur dioxide occurred in 2006 at any of the seven SCAQMD locations monitored. Though sulfur dioxide concentrations remain well below the standards, sulfur dioxide is a precursor to sulfate, which is a component of fine particulate matter, PM10, and PM2.5. Standards for PM10 and PM2.5 were both exceeded in 2006. Sulfur dioxide was not measured at SSAB sites in 2006. Historical measurements showed concentrations to be well below standards and monitoring has been discontinued.

Particulate Matter (PM10 and PM2.5)

Of great concern to public health are the particles small enough to be inhaled into the deepest parts of the lung. Respirable particles (particulate matter less than about 10 micrometers in diameter) can accumulate in the respiratory system and aggravate health problems such as asthma, bronchitis and other lung diseases. Children, the elderly, exercising adults, and those suffering from asthma are especially vulnerable to adverse health effects of PM10 and PM2.5.

A consistent correlation between elevated ambient fine particulate matter (PM10 and PM2.5) levels and an increase in mortality rates, respiratory infections, number and severity of asthma attacks and the number of hospital admissions has been observed in different parts of the United States and various areas around the world. Studies have reported an association between long term exposure to air pollution dominated by fine particles (PM2.5) and increased mortality, reduction in life-span, and an increased mortality from lung cancer.

Daily fluctuations in fine particulate matter concentration levels have also been related to hospital admissions for acute respiratory conditions, to school and kindergarten absences, to a decrease in respiratory function in normal children and to increased medication use in children and adults with asthma. Studies have also shown lung function growth in children is reduced with long-term exposure to particulate matter.

The elderly, people with pre-existing respiratory and/or cardiovascular disease and children appear to be more susceptible to the effects of PM10 and PM2.5.

The SCAQMD monitored PM10 concentrations at 20 locations in 2006. Highest PM10 concentrations were recorded in Riverside and San Bernardino counties in and around the Metropolitan Riverside County area and further inland in San Bernardino Valley areas. The federal 24-hour standard was not exceeded at any of the locations monitored in 2005. The much more stringent state standards were exceeded in most areas.

The SCAQMD began regular monitoring of PM2.5 in 1999 following the U.S. EPA's adoption of the national PM2.5 standards in 1997. In 2005, PM2.5 concentrations were monitored at 19 locations throughout the district. Maximum 24-hour average concentration has increased at some locations compared to 2001, the basis of the 2003 AQMP air quality data. The PM2.5 annual average concentrations and the highest 98th percentile PM2.5 concentrations (which the federal 24-hour PM2.5 standard is based on), however, are lower than 2001 levels at all locations monitored.

Similar to PM10 concentrations, PM2.5 concentrations were higher in the inland valley areas of San Bernardino and Metropolitan Riverside counties. However, PM2.5 concentrations were also high in the metropolitan area of Los Angeles County. The high PM2.5 concentrations in Los Angeles County are mainly due to the secondary formation of smaller particulates resulting from mobile and stationary source activities. In contrast to PM10, PM2.5 concentrations were low in the Coachella Valley area of SSAB. PM10 concentrations are normally higher in the desert areas due to windblown and fugitive dust emissions.

Lead

Lead in the atmosphere is present as a mixture of a number of lead compounds. Leaded gasoline and lead smelters have been the main sources of lead emitted into the air. Due to the phasing out of leaded gasoline, there was a dramatic reduction in atmospheric lead in the Basin over the past two decades.

Fetuses, infants, and children are more sensitive than others to the adverse effects of lead exposure. Exposure to low levels of lead can adversely affect the development and function of the central nervous system, leading to learning disorders, distractibility, inability to follow simple commands, and lower intelligence quotient. In adults, increased lead levels are associated with increased blood pressure.

Lead poisoning can cause anemia, lethargy, seizures, and death. It appears that there are no direct effects of lead on the respiratory system. Lead can be stored in the bone from early-age environmental exposure, and elevated blood lead levels can occur due to breakdown of bone tissue during pregnancy, hyperthyroidism (increased secretion of hormones from the thyroid gland), and osteoporosis (breakdown of bony tissue). Fetuses and breast-fed babies can be exposed to higher levels of lead because of previous environmental lead exposure of their mothers.

The federal and state standards for lead were not exceeded in any area of the SCAQMD in 2005. There have been no violations of the standards at the SCAQMD's regular air monitoring stations since 1982, as a result of removal of lead from gasoline. The maximum quarterly average lead concentration (0.03 μg/m3) was two percent of the federal standard. Additionally, special monitoring stations immediately adjacent to stationary sources of lead (e.g., lead smelting facilities) have not recorded exceedances of the standards in localized areas of the Basin since 1991 and 1994 for the federal and state standards, respectively. The maximum monthly and quarterly average lead concentration (0.44 μg/m3 and 0.34 μg/m3 in Central Los Angeles), measured at special monitoring sites immediately adjacent to stationary sources of lead were 29 and 23 percent of the state and federal standards, respectively. No lead data were obtained at SSAB and Orange County stations in 2005, and because historical lead data showed concentrations in SSAB and Orange County areas to be well below the standard, measurements have been discontinued.

Sulfates

Sulfates are chemical compounds which contain the sulfate ion and are part of the mixture of solid materials which make up PM10. Most of the sulfates in the atmosphere are produced by oxidation of sulfur dioxide. Oxidation of sulfur dioxide yields sulfur trioxide (SO3) which reacts with water to form sulfuric acid, which contributes to acid deposition. The reaction of sulfuric acid with basic substances such as ammonia yields sulfates, a component of PM10 and PM2.5.

Most of the health effects associated with fine particles and sulfur dioxide at ambient levels are also associated with sulfates. Thus, both mortality and morbidity effects have been observed with an increase in ambient sulfate concentrations. However, efforts to separate the effects of sulfates from the effects of other pollutants have generally not been successful.

Clinical studies of asthmatics exposed to sulfuric acid suggest that adolescent asthmatics are possibly a subgroup susceptible to acid aerosol exposure. Animal studies suggest that acidic particles such as sulfuric acid aerosol and ammonium bisulfate are more toxic than non-acidic particles like ammonium sulfate. Whether the effects are attributable to acidity or to particles remains unresolved.

In 2005, the state sulfate standard was not exceeded anywhere in the Basin. No sulfate data were obtained at SSAB and Orange County stations in 2005. Historical sulfate data showed concentrations in the SSAB and Orange County areas to be well below the standard, and measurements have been discontinued.

Visibility Reducing Particles

Since deterioration of visibility is one of the most obvious manifestations of air pollution and plays a major role in the public's perception of air quality, the state of California has adopted a standard for visibility or visual range. Until 1989, the standard was based on visibility estimates made by human observers. The standard was changed to require measurement of visual range using instruments that measure light scattering and absorption by suspended particles.

Volatile Organic Compounds

It should be noted that there are no state or national ambient air quality standards for VOCs because they are not classified as criteria pollutants. VOCs are regulated, however, because limiting VOC emissions reduces the rate of photochemical reactions that contribute to the formation of ozone. They are also transformed into organic aerosols in the atmosphere, contributing to higher PM10 and lower visibility levels.

Although health-based standards have not been established for VOCs, health effects can occur from exposures to high concentrations of VOCs because of interference with oxygen uptake. In general, ambient VOC concentrations in the atmosphere are suspected to cause coughing, sneezing, headaches, weakness, laryngitis, and bronchitis, even at low concentrations. Some hydrocarbon components classified as VOC emissions are thought or known to be hazardous. Benzene, for example, one hydrocarbon component of VOC emissions, is known to be a human carcinogen.

Greenhouse Gases

The SCAQMD adopted a "Policy on Global Warming and Stratospheric Ozone Depletion" on April 6, 1990. The policy commits the SCAQMD to consider global impacts in rulemaking and in drafting revisions to the AQMP. In March 1992, the SCAQMD Governing Board reaffirmed this policy and adopted amendments to the policy to include the following directives:

- phase out the use and corresponding emissions of chlorofluorocarbons (CFCs), methyl chloroform (1,1,1-trichloroethane or TCA), carbon tetrachloride, and halons by December 1995;
- phase out the large quantity use and corresponding emissions of hydrochlorofluorocarbons (HCFCs) by the year 2000;
- develop recycling regulations for HCFCs;
- develop an emissions inventory and control strategy for methyl bromide; and,
- support the adoption of a California greenhouse gas emission reduction goal.

Gases that trap heat in the atmosphere are often called greenhouse gases (GHGs), comparable to a greenhouse. GHGs are emitted by natural processes and human activities. The accumulation of greenhouse gases in the atmosphere regulates the earth's temperature. Global warming is the observed increase in average temperature of the earth's surface and atmosphere. The primary cause of global warming is an increase of GHGs in the atmosphere. The six major GHGs are carbon dioxide (CO2), methane (CH4), nitrous oxide (N2O), sulfur hexafluoride (SF6), hydrofluorocarbons (HFCs), and perfluorocarbon (PFCs). The GHGs absorb longwave radiant energy emitted by the Earth, which warms the atmosphere. The GHGs also emit longwave radiation both upward to space and back down toward the surface of the Earth. The downward part of this longwave radiation emitted by the atmosphere is known as the "greenhouse effect." Emissions from human activities such as electricity production and vehicles have elevated the concentration of these gases in the atmosphere.

CO2 is an odorless, colorless natural greenhouse gas. Natural sources include the following: decomposition of dead organic matter; respiration of bacteria, plants, animals, and fungus; evaporation from oceans; and volcanic outgassing. Anthropogenic (human caused) sources of CO2 are from burning coal, oil, natural gas, and wood. CH_4 is a flammable gas and is the main component of natural gas. N_2O, also known as laughing gas, is a colorless greenhouse gas. Some industrial processes (fossil fuel-fired power plants, nylon production, nitric acid production, and vehicle emissions) also contribute to its atmospheric load. HFCs are synthetic man-made chemicals that are used as a substitute for chlorofluorocarbons (whose production was stopped as required by the Montreal Protocol) for automobile air conditioners and refrigerants. The two main sources of PFCs are primary aluminum production and semiconductor manufacture. SF_6 is an inorganic, odorless, colorless, nontoxic, nonflammable gas. SF_6 is used for insulation in electric power transmission and distribution equipment, in the magnesium industry, in semiconductor manufacturing, and as a tracer gas for leak detection.

Scientific consensus, as reflected in recent reports issued by the United Nations Intergovernmental Panel on Climate Change, is that the majority of the observed warming over the last 50 years can be attributable to increased concentration of GHGs in the atmosphere due to human activities. Industrial activities, particularly increased consumption of fossil fuels (e.g., gasoline, diesel, wood, coal, etc.), have heavily contributed to the increase in atmospheric levels of GHGs. As reported by the California Energy Commission (CEC), California contributes 1.4 percent of the global and 6.2 percent of the national GHGs emissions (CEC, 2004). The GHG inventory for California is presented in Table 3-3 (CEC, 2005). Approximately 80 percent of GHGs in California are from fossil fuel combustion (see Table 3-3).

In June 2005, Governor Schwarzenegger signed Executive Order #S-3-05 which established the following greenhouse gas reduction targets:

- By 2010, Reduce to 2000 Emission Levels,
- By 2020, Reduce to 1990 Emission Levels, and
- By 2050, Reduce to 80 percent below 1990 Levels.

Table 3-3
California GHG Emissions and Sinks Summary
(Million metric tons of CO_2 equivalence)

Gas/Source	1990	2004
Carbon Dioxide (Gross)	**317.4**	**355.9**
Fossil Fuel Combustion	306.4	342.4
Residential	29.0	27.9
Commercial	12.6	12.2
Industrial	66.1	67.1
Transportation	161.1	188.0
Electricity Generation (In State)	36.5	47.1
No End Use Specified	1.1	0.2
Cement Production	4.6	6.5
Lime Production	0.2	0.1
Limestone & Dolomite Consumption	0.2	0.3
Soda Ash Consumption	0.2	0.2
Carbon Dioxide Consumption	0.1	0.1
Waste Combustion	0.1	0.1
Land Use Change & Forestry Emissions	5.5	6.1
Land Use Change & Forestry Sinks	(22.7)	(21.0)
Carbon Dioxide (Net)	**294.7**	**334.9**
Methane (CH4)	**26.0**	**27.9**
Petroleum & Natural Gas Supply System	1.0	0.5
Natural Gas Supply System	1.6	1.4
Landfills	8.1	8.4
Enteric Fermentation	7.5	7.2
Manure Management	3.3	6.0
Flooded Rice Fields	0.4	0.6
Burning Ag & Other Residues	0.1	0.1
Wastewater Treatment	1.4	1.7
Mobile Source Combustion	1.2	0.6
Stationary Source Combustion	1.3	1.3
Nitrous Oxide (N2O)	**32.7**	**33.3**
Nitric Acid Production	0.4	0.2
Waste Combustion	0.0	0.0
Agricultural Soil Management	14.7	19.2
Manure Management	0.8	0.9
Burning Ag Residues	0.1	0.1
Wastewater	0.9	1.1
Mobile Source Combustion	15.6	11.8
Stationary Source Combustion	0.2	0.2
High Global Warming Potential Gases (HFCs, PFCs & SF6)	**7.1**	**14.2**
Substitution of Ozone-Depleting Substances	4.5	12.6
Semiconductor Manufacture	0.4	0.6
Electricity Transmission & Distribution (SF6)	2.3	1.0
Gross California Emissions (w/o Electric Imports)	**383.3**	**431.3**
Land Use Change & Forestry Sinks	**(22.7)**	**(21.0)**
Net Emissions (w/o Electric Imports)	**360.6**	**410.3**
Electricity Imports	**43.3**	**60.8**
Gross California Emissions with Electricity Imports	**426.6**	**492.1**
Net California Emissions with Electricity Imports	**403.9**	**471.1**

Source: CEC, 2005

On September 27, 2006, Assembly Bill (AB) 32, the California Global Warming Solutions Act, of 2006 was enacted by the State of California and signed by Governor Schwarzenegger. AB32 expanded on Executive Order #S-3-05. The legislature stated that "global warming poses a serious threat to the economic well-being, public health, natural resources, and the environment of California." AB32 represents the first enforceable state-wide program in the U.S. to cap all GHG emissions from major industries that includes penalties for non-compliance. While acknowledging that national and international actions will be necessary to fully address the issue of global warming, AB32 lays out a program to inventory and reduce greenhouse gas emissions in California and from power generation facilities located outside the state that serve California residents and businesses.

AB32 will require CARB to:

- Establish a statewide GHG emissions cap for 2020, based on 1990 emissions by January 1, 2008;
- Adopt mandatory reporting rules for significant sources of GHG by January 1, 2008;
- Adopt an emissions reduction plan by January 1, 2009, indicating how emissions reductions will be achieved via regulations, market mechanisms, and other actions; and
- Adopt regulations to achieve the maximum technologically feasible and cost-effective reductions of GHG by January 1, 2011.

The combination of Executive Order #S-3-05 and AB32 will require significant development and implementation of energy efficient technologies and shifting of energy production to renewable sources.

Climate Change

Global climate change is a change in the average weather of the earth, which can be measured by wind patterns, storms, precipitation, and temperature. Historical records have shown that temperature changes have occurred in the past, such as during previous ice ages. Some data indicate that the current temperature record differs from previous climate changes in rate and magnitude.

The United Nations Intergovernmental Panel on Climate Change constructed several emission trajectories of greenhouse gases needed to stabilize global temperatures and climate change impacts. It concluded that a stabilization of greenhouse gases at 400-450 ppm carbon dioxide-equivalent concentration is required to keep global mean warming below 2° Celsius, which is assumed to be necessary to avoid dangerous climate change.

The potential health effects from global climate change may arise from temperature increases, climate-sensitive diseases, extreme events, and air quality. There may be direct temperature effects through increases in average temperature leading to more extreme heat waves and less extreme cold spells. Those living in warmer climates are likely to experience more stress and heat-related problems (i.e., heat rash and heat stroke). In addition, climate sensitive diseases may increase, such as those spread by mosquitoes and other disease carrying insects. Those diseases include malaria, dengue fever, yellow fever, and encephalitis. Extreme events such as flooding and hurricanes can displace people and agriculture, which would have negative consequences. Drought in some areas may increase, which would decrease water and food availability. Global warming may also contribute to air quality problems from increased frequency of smog and particulate air pollution.

The impacts of climate change will also affect projects in various ways. Effects of climate change are specifically mentioned in AB 32 such as rising sea levels and changes in snow pack. The extent of climate change impacts at specific locations remains unclear. However, it is expected that California agencies will more precisely quantify impacts in various regions of the State. As an example, it is expected that the Department of Water Resources will formalize a list of foreseeable water quality issues associated with various degrees of climate change. Once state government agencies make these lists available, they could be used to more precisely determine to what extent a project creates global climate change impacts.

Toxic Air Contaminants

Historically, the SCAQMD has regulated criteria air pollutants using either a technology-based or an emissions limit approach. The technology-based approach defines specific control technologies that may be installed to reduce pollutant emissions. The emission limit approach establishes an emission limit, and allows industry to use any emission control equipment, as long as the emission requirements are met. The regulation of toxic air contaminants (TACs) requires a similar regulatory approach as explained in the following subsections.

<u>Control of TACs under the TAC Identification and Control Program</u>

California's TAC identification and control program, adopted in 1983 as Assembly Bill (AB) 1807, is a two-step program in which substances are identified as TACs, and airborne toxic control measures (ATCMs) are adopted to control emissions from specific sources. CARB has adopted a regulation designating all 188 federal hazardous air pollutants (HAPs) as TACs.

ATCMs are developed by CARB and implemented by the SCAQMD and other air districts through the adoption of regulations of equal or greater stringency. Generally, the ATCMs reduce emissions to achieve exposure levels below a determined health threshold. If no such threshold levels are determined, emissions are reduced to the lowest level achievable through the best available control technology unless it is determined that an alternative level of emission reduction is adequate to protect public health.

Under California state law, a federal National Emission Standard for Hazardous Air Pollutants (NESHAP) automatically becomes a state ATCM, unless CARB has already adopted an ATCM for the source category. Once a NESHAP becomes an ATCM, CARB and the air pollution control or air quality management district have certain responsibilities related to adoption or implementation and enforcement of the NESHAP/ATCM.

<u>Control of TACs under the Air Toxics "Hot Spots" Act</u>

The Air Toxics Hot Spots Information and Assessment Act of 1987 (AB2588) establishes a state-wide program to inventory and assess the risks from facilities that emit TACs and to notify the public about significant health risks associated with the emissions. Facilities are phased into the AB2588 program based on their emissions of criteria pollutants or their occurrence on lists of toxic emitters compiled by the SCAQMD. Phase I consists of facilities that emit over 25 tons per year of any criteria pollutant and facilities present on the SCAQMD's toxics list. Phase I facilities entered the program by reporting their air TAC emissions for calendar year 1989. Phase II consists of facilities that emit between 10 and 25 tons per year of any criteria pollutant, and submitted air toxic inventory reports for calendar year 1990 emissions. Phase III consists of certain designated types of facilities which emit less than 10 tons per year of any criteria pollutant, and submitted inventory reports for calendar year 1991 emissions. Inventory reports are required to be updated every four years under the state law.

In October 1992, the SCAQMD Governing Board adopted public notification procedures for Phase I and II facilities. These procedures specify that AB2588 facilities must provide public notice when exceeding the following risk levels:

- Maximum Individual Cancer Risk: greater than 10 in 1 million (10×10^{-6})
- Total Hazard Index: greater than 1.0 for TACs except lead, or > 0.5 for lead

Public notice is to be provided by letters mailed to all addresses and all parents of children attending school in the impacted area. In addition, facilities must hold a public meeting and provide copies of the facility risk assessment in all school libraries and a public library in the impacted area.

The SCAQMD continues to complete its review of the health risk assessments submitted to date and may require revision and resubmission as appropriate before final approval. Notification will be required from facilities with a significant risk under the AB2588 program based on their initial approved health risk assessments and will continue on an ongoing basis as additional and subsequent health risk assessments are reviewed and approved.

Control of TACs with Risk Reduction Audits and Plans

Senate Bill (SB) 1731, enacted in 1992 and codified at Health and Safety Code §44390 et seq., amended AB2588 to include a requirement for facilities with significant risks to prepare and implement a risk reduction plan which will reduce the risk below a defined significant risk level within specified time limits. SCAQMD Rule 1402 - Control of Toxic Air Contaminants from Existing Sources, was adopted on April 8, 1994, to implement the requirements of SB1731.

In addition to the TAC rules adopted by SCAQMD under authority of AB1807 and SB1731, the SCAQMD has adopted source-specific TAC rules, based on the specific level of TAC emitted and the needs of the area. These rules are similar to the state's ATCMs because they are source-specific and only address emissions and risk from specific compounds and operations.

Cancer Risks from Toxic Air Contaminants

New and modified sources of toxic air contaminants in the SCAQMD are subject to Rule 1401 - New Source Review of Toxic Air Contaminants and Rule 212 - Standards for Approving Permits. Rule 212 requires notification of the SCAQMD's intent to grant a permit to construct a significant project, defined as a new or modified permit unit located within 1000 feet of a school (a state law requirement under AB3205), a new or modified permit unit posing an maximum individual cancer risk of one in one million (1×10^{-6}) or greater, or a new or modified facility with criteria pollutant emissions exceeding specified daily maximums. Distribution of notice is required to all addresses within a 1/4-mile radius, or other area deemed appropriate by the SCAQMD. Rule 1401 currently controls emissions of carcinogenic and non-carcinogenic (health effects other than cancer) air contaminants from new, modified and relocated sources by specifying limits on cancer risk and hazard index (explained further below), respectively.

Health Effects

One of the primary health risks of concern due to exposure to TACs is the risk of contracting cancer. The carcinogenic potential of TACs is a particular public health concern because it is currently believed by many scientists that there is no "safe" level of exposure to carcinogens. Any exposure to a carcinogen poses some risk of causing cancer. It is currently estimated that about one in four deaths in the United States is attributable to cancer. About two percent of cancer deaths in the United States may be attributable to environmental pollution (Doll and Peto 1981). The proportion of cancer deaths attributable to air pollution has not been estimated using epidemiological methods.

Non-Cancer Health Risks from Toxic Air Contaminants

Unlike carcinogens, for most noncarcinogens it is believed that there is a threshold level of exposure to the compound below which it will not pose a health risk. The California Environmental Protection Agency (CalEPA) Office of Environmental Health Hazard Assessment develops Reference Exposure Levels (RELs) for TACs which are health-conservative estimates of the levels of exposure at or below which health effects are not expected. The noncancer health risk due to exposure to a TAC is assessed by comparing the estimated level of exposure to the REL. The comparison is expressed as the ratio of the estimated exposure level to the REL, called the hazard index (HI).

Existing Emissions from Rule 1110.2 Engines

SCAQMD staff conducted a survey in 2005 of non-agricultural, stationary, non-emergency engines. Operators at a total of 580 facilities were contacted, and 313 of those facility operators responded (54 percent facility response rate). The survey collected data for 631 out of a total of 907 active engines (70 percent response rate based on number of engines). Emissions were calculated based on fuel consumption data gathered via the survey, but because source test emissions data often underestimate actual emissions, Rule 1110.2 concentration limits were used for some of the engines to make the estimates more realistic. The resulting calculated total emissions for all survey engines were scaled up to account for the percent response rate by engine category to obtain a complete emissions inventory for the entire universe of regulated engines.

Unannounced Compliance Testing

A program of unannounced compliance testing conducted by SCAQMD's Compliance Division revealed that, although engines can generally meet emission limits when emission control systems are properly maintained and adjusted as is generally the case at the time of source testing; emissions during normal operation frequently exceed the emission limits. The tendency for an engine to have excess emissions will differ depending upon whether it is a rich-burn or lean-burn engine, what emission limits it must meet, BACT or Rule 1110.2, and whether or not it has a CEMS. Newer engines would have been subject to more stringent BACT requirements than the source-specific requirements in Rule 1110.2. Table 3-4 shows the average ratio of measured emissions to allowed emissions found in the testing program with engines categorized based on these three parameters.

Table 3-4
Average Ratio of Measured Emission to Allowed Emission Found in Unannounced Testing

Rich/Lean	Limits	CEMS	Tests	NOx	CO
Lean	BACT	No	3	1.81	0.33
Lean	BACT	Yes	7	0.76	0.39
Lean	Rule	No	1	0.89	0.10
Rich	BACT	No	169	5.19	5.21
Rich	BACT	Yes	8	0.11	37.76
Rich	Rule	No	39	2.12	0.70

In 1993 the SCAQMD adopted Regulation XX – RECLAIM. This regulation established a NOx and SOx cap-and-trade emission reduction market program that required over 300 of the largest emitting facilities in the district to meet the requirements of that program rather than the requirements of specified source-specific SCAQMD Rules. Therefore, while some engines in the district are not subject to the NOx requirements of Rule 1110.2; they are still subject to the VOC and CO requirements of Rule 1110.2.

Excess emissions of both NOx and CO were clearly evident from rich-burn engines with BACT limits not having CEMS. Excess emissions of CO were evident from rich-burn engines with BACT limits having CEMS and of NOx from rich-burn engines with Rule 1110.2 limits not having CEMS. Although there was some suggestion of excess NOx emissions from lean-burn engines with BACT limits not having CEMS, the number of tests was considered too small to be conclusive and, because of the inherently low emissions of this type of engine, lean-burn engines are less likely to have large exceedances. There were no tests on rich-burn engines with Rule 1110.2 limits having CEMS.

To estimate the extent of excess emissions from the entire population of engines in the district (actual emissions), staff applied factors to the allowed emission rates from each engine for which survey data were available. These factors were based on the ratios derived from the results of unannounced testing summarized in Table 3-4. Since VOC emissions were not measured, to estimate excess VOC emissions from each engine, the same CO factor was also applied to the allowed VOC emission rates based on the general observation that these pollutants generally trend together, i.e., rise or fall in the same direction.

Table 3-5 summarizes the calculated emissions based on the survey data, the estimated excess emissions based on the average exceedance factors found in compliance testing and the resulting total calculated/estimated emissions from stationary, non-emergency engines.

Table 3-5
Emissions from Stationary, Non-Emergency Engines

Description	NOx	CO	VOC	SOx	PM-2.5	CO2
Annual, tons/year	1,678	9,947	459	101	160	1,249,971
Daily, pounds/day	9,195	54,506	2,517	551	877	6,849,158

ENERGY

In 2005, 37 percent of the petroleum came from in-state, with 21 percent coming from Alaska, and 42 percent being supplied by foreign sources. Also in 2005, 78 percent of the electricity came from instate sources, while 22 percent was imported into the state. The electricity imported totaled 62,456 gigawatt hours (gW-hours), with 20,286 gW-hours coming from the Pacific Northwest, 42,170 gW-hours from the Southwest. (Note: A gigawatt is equal to one million kilowatts). For natural gas in 2005, 38 percent came from the Southwest, 23 percent from Canada, 15 percent from in-state, and 24 percent from the Rockies.[12]

Electricity Production

Assembly Bill 1890, which was signed into law in 1996, attempted to restructure California's electricity market. Flaws in the market design combined with natural gas supply shortages and a number of other factors to produce an energy crisis in the state that resulted in numerous rolling blackouts, huge electricity price spikes, and bankruptcy or near-bankruptcy for two of the state's private utilities. The legislature responded by rescinding much of the deregulation scheme, creating a new state power authority, and enacting emergency energy conservation measures, mostly in the form of rebates and incentives. Currently, it is not clear whether lawmakers will choose to try again with a restructured market, or return to the former regulated market. This uncertainty has deterred many private investors from pursuing energy projects, meaning that the state, and the region's, future energy supply is far from assured.

Power plants in California provide approximately 85 percent of the in-state electricity demand. Hydroelectric power from the Pacific Northwest provides another 2.6 percent, down due to drought conditions in recent years, and power plants in the Southwestern U.S. provide another 13 percent. The relative contribution of in-state and out-of-state power plants depends upon, among other factors, the precipitation that occurred in the previous year and the corresponding amount of hydroelectric power that is available. Two of the largest power plants in California are located in southern California: Alamitos and Redondo Beach. Both of these plants consume natural gas. San Onofre, the state's largest power plant in terms of net capability, is nuclear powered and is located in San Diego County.

Local electricity distribution service is provided to customers within southern California by one of two privately owned utilities – either Southern California Edison Company or San Diego-based Sempra Energy – or by a publicly-owned utility, such as the Los Angeles Department of Water and Power and the Imperial Irrigation District.

Southern California Edison is the largest electricity utility in southern California with a service area that covers all or nearly all of Orange, San Bernardino, and Ventura counties, and most of Los Angeles and Riverside counties. Southern California Edison Company provides approximately 70 percent of the total electricity demand in southern California. Sempra Energy provides local distribution service to the southern portion of Orange County.

The Los Angeles Department of Water and Power is the largest of the publicly owned electric utilities in southern California. Los Angeles Department of Water and Power provides electricity service to most customers located in the City of Los Angeles and provides approximately 20 percent of the total electricity demand in the Basin. Other cities that operate their own electric utilities in southern California include Burbank, Glendale, Pasadena, Azusa, Vernon, Anaheim, Riverside, Banning, and Colton. Two water districts provide local electric service within the southern California: Imperial Irrigation District and Southern California Water Company. Imperial Irrigation District provides electricity to

[12] CEC, California's Major Source of Energy, December 2005.

customers in Imperial County and the Coachella Valley portion of Riverside County. Southern California Water Company provides electric service to the community of Big Bear. Anza Electric Cooperative provides local distribution service to the Anza Valley area of southern Riverside County.[13]

Table 3-6 shows the amount of electricity delivered to residential and nonresidential entities in the counties in the Basin.

Table 3-6
California Utility Electricity Deliveries for 2000

County	Residential		Non-residential		Total	
	Number of Accounts	kWh[1] (million)	Number of Accounts	kWh (million)	Number of Accounts	kWh (million)
Los Angeles	2,956,616	18,342	356,167	45,577	3,312,783	63,919
Orange	878,934	6,092	120,907	13,612	999,841	19,704
Riverside	500,171	4,396	157,503	6,425	657,674	10,821
San Bernardino	547,654	3,774	67,131	8,093	914,785	11,867
Total	4,883,375	32,604	701,708	73,707	5,885,083	106,311

California Energy Commission, California Gross System Electricity Production for 2005, December 2005.
[1] kilowatt-hour (kWh): The most commonly-used unit of measure telling the amount of electricity consumed over time. It means one kilowatt (1000 watts) of electricity supplied for one hour.

Natural Gas

Four regions supply California with natural gas. Three of them—the Southwestern U.S., the Rocky Mountains, and Canada—supplied 87 percent of all the natural gas consumed in California in 2004. The remainder is produced in California. In 2004, approximately 50 percent of all the natural gas consumed in California was used to generate electricity. Residential consumption represented approximately 22 percent of California's natural gas use with the balance consumed by the industrial, resource extraction, and commercial sectors.

Southern California Gas Company, a privately-owned utility company, provides natural gas service throughout the district, except for the City of Long Beach, the southern portion of Orange County, and portions of San Bernardino County. The service area for the Long Beach Gas & Electric Department, a municipal utility owned and operated by the City of Long Beach, includes the cities of Long Beach and Signal Hill, and sections of surrounding communities, including Lakewood, Bellflower, Compton, Seal Beach, Paramount, and Los Alamitos. San Diego Gas & Electric Company provides natural gas service to the southern portion of Orange County. In San Bernardino County, Southwest Gas Corporation provides natural gas service to Victorville, Big Bear, Barstow, and Needles.[14]

Table 3-7 provides the estimated use of natural gas in California by residential, commercial and industrial sectors. In 2005, about 67 percent of the natural gas consumed in California was for industrial and electric generation purposes.

[13] SCAG, 2005 Regional Transportation Plan Program Environmental Report. January 2005
[14] SCAG, 2005 Regional Transportation Plan Program Environmental Report. January 2005 and CEC, 2004 Natural Gas Use in California.

Table 3-7
California Natural Gas Demand 2005
(Million Cubic Feet per Day – MMcf/day)

Sector	Utility	Non-Utility	Total
Residential	1,286	--	1,286
Commercial	567	--	567
Industrial	844	630	1,474
Electric Generation	1,711	683	2,394
Total	4,419	1,313	5,732

Source: CEC, California Natural Gas Demand -2005, 2006.

Liquid Petroleum Fuels

California is currently ranked fourth in the nation among oil producing states, behind Louisiana, Texas, and Alaska, respectively. Crude oil production in California averaged 731,150 barrels per day in 2004, a decline of 4.7 percent from 2003. Statewide oil production has declined to levels not seen since 1943. In 2005, the total receipts to refineries of roughly 674 million barrels came from in-state oil production (39.4 percent), combined with oil from Alaska (20.1 percent), and foreign sources (40.4 percent).[15]

California is a major refining center for West Coast petroleum markets with combined crude oil distillation capacity totaling more than 1.9 million barrels per day, ranking the state third highest in the nation. California ranks first in the U.S. in gasoline consumption and second in jet fuel consumption.

A large network of crude oil pipelines connects producing areas with refineries that are located in the San Francisco Bay area, Los Angeles area and the Central Valley. Major ports in northern and southern California receive Alaska North Slope and foreign crude oil for processing in many of the state's 21 refineries.

Most gasoline and diesel fuel sold in California for on-road motor vehicles is refined in California to meet state-specific formulations required by CARB. Major petroleum refineries in California are concentrated in three counties: Contra Costa County in northern California, Kern County in central California, and Los Angeles County in southern California. In Los Angeles County, petroleum refineries are located mostly in the southern portion of the county.[16]

In 2001, refineries in California processed approximately 655 million barrels of crude oil. Almost half of the crude oil came from in-state oil production facilities; 21 percent came from Alaska; and the remaining (approximately 29 percent) came from foreign sources. The long-term oil supply outlook for California remains one of declining in-state and Alaska supplies leading to increasing dependence on foreign oil sources.[16]

California's Renewable Energy Program

California's Renewable Portfolio Standard (RPS) was developed under Senate Bills 1038, 1078, 1250 and 107. The senate bills require retail sellers of electricity to increases the

[15] CEC, Oil and Petroleum in California, December 2006.
[16] SCAG, 2005 Regional Transportation Plan Program Environmental Report. January 2005 and CEC, 2004 Natural Gas Use in California.

amount of renewable energy they procure by one percent each year until 20 percent of total retail sales are served with renewable energy by December 31, 2010.

The Energy Commission's 2003 Integrated Energy Policy Report recommended accelerating that goal to 2010, and the 2004 Energy Report Update further recommended increasing the target to 33 percent by 2020. The state's Energy Action Plan supported this goal.

On April 25, 2006, Governor Schwarzenegger signed Executive Order S-06-06. The Executive Order established targets for the production and use of biofuels and biopower, and directed state agencies with important biomass connections to work together to advance biomass programs in California, while providing environmental protection and mitigation. The Executive Order S-06-06 targets 20 percent biofuel by 2010, 40 percent by 2020 and 75 by 2050. Governor Schwarzenegger targeted biomass to contribute 20 percent of the goal for renewable electricity generated under RPS for the 2012 and 2020 goals.

The CEC's Renewable Energy Program (REP) provides funding for renewable facilities as long as 25 percent of the total energy input was comprised of energy from fossil fuels during a calendar year. Any facility that is developed and awarded a power purchase contract as a result of an Interim RPS procurement solicitation approved by the CPUC under Decisions 02-08-071 and 02-10-062 may use up to 25 percent fossil fuel and attribute 100 percent of the electricity generated as RPS-eligible.[17]

In 2002, the total electrical generation capacity from existing landfill gas to electricity projects in California was 211 MW. At that time there were 26 planned landfill gas to energy facilities with a potential of 39 MW. Approximately 45 MW of electrical potential was projected if existing landfill gas to energy projects were expanded to full capacity. Approximately 163 MW was estimated to be available from landfills that did not generate electricity at the time.

The CEC Reconciliation of Retailer Claims, Commission Report presents a table of the 2005 Gross System Power by fuel type. The table is reproduced here as Table 3-8.

[17] California Energy Commission, Renewable Portfolio Standard Eligibility, Second Edition, CEC-300-2007-006-CMF, March 2007.

Table 3-8
2005 Gross System Power[18]

Fuel Type	System Power
Eligible Renewable	10.7%
-Biomass & waste	2.1%
-Geothermal	5.0%
-Small hydroelectric	1.9%
-Solar	0.2%
-Wind	1.5%
Coal	20.1%
Large hydroelectric	17.0%
Natural gas	37.7%
Nuclear	14.5%
Other	0.0%
Total	100.00%

Table 3-9 shows the percentage of system power by renewable fuel type based on the values in Table 3-8. As seen in Table 3-9, biomass and waste comprises 20 percent of the eligible renewable energy.

Table 3-9
2005 Renewable System Power

Fuel Type	System Power
Biomass & waste	20%
Geothermal	47%
Small hydroelectric	18%
Solar	2%
Wind	14%
Total	100%

The RPS has consists of three utilities: Pacific Gas and Electric, Southern California Edison, and San Diego Gas and Electric. SCE provides most of the electricity for the district. Table 3-10 shows that of the total renewable energy procurement SCE provides 66 percent of the state biogas and no municipal solid waste to the RPS. Table 3-11 shows that of the total renewable energy procurement SDG&E provides 20 percent of the state biogas and no municipal solid waste to the RPS.

[18] California Energy Commission, Reconciliation of Retailer Claims, Commission Report, CEC-300-2006-016-F, October 2006.

Table 3-10
2005 SCE Renewable System Power[19]

Fuel	Total Procurement (MW-hour)	SCE Procurement (MW-hour)	Percent of SCE Procurement	Percent of Total Procurement
Biomass	3,614,079	379,119	3%	10%
Biogas	1,110,233	737,262	6%	66%
Geothermal	9,504,152	7,823,442	61%	82%
Municipal Solid Waste	139,882	0	0%	0%
Small Hydro	3,743,740	867,171	7%	23%
Solar	622,100	622,100	5%	100%
Wind	3,665,933	2,495,301	19%	68%
Various From Net Metering	0	0	0%	
Total Renewable Procurement	22,400,119	12,924,395	100%	58%

Table 3-11
2005 SDG&E Renewable System Power[20]

Fuel	Total Procurement (MW-hour)	SDG&E Procurement (MW-hour)	Percent of SDG&E Procurement	SDG&E Percent of Total Procurement
Biomass	3,614,079	298,945	36%	8%
Biogas	1,110,233	218,223	26%	20%
Geothermal	9,504,152	0	0%	0%
Municipal Solid Waste	139,882	0	0%	0%
Small Hydro	3,743,740	11,764	1%	0%
Solar	622,100	0	0%	0%
Wind	3,665,933	296,434	36%	8%
Various From Net Metering	0	0	0%	
Total Renewable Procurement	22,400,119	825,366	100%	4%

In-state electricity from biomass comprises two percent of the total electricity capacity in California and more than two percent to its electrical energy supply. In Executive Order S-06-06 Governor Schwarzenegger targeted biomass to contribute 20 percent of the goal for renewable electricity generated under RPS. Table 3-12 presents biomass capacities for California.

The CEC states that 305 MW are available from landfill gas operations and 68 MW from digester gas operations in California. Based on 974 MW of total biomass electrical capacity in the state landfill gas operations could provide 31 percent of the total potential biomass electrical capacity and digester operations could provide 38 percent of the total potential biomass electrical capacity. The total potential biomass electrical capacity is the amount of electricity available from all existing and future biomass sources. The term "potential" is used because not all of the sources may be converted to electricity producing sources.

[19] California Energy Commission, Renewable Portfolio Standard 2005 Procurement Verification, Staff Draft Report, CEC-300-2007-001-SD, March 2007
[20] CEC, March 2007, ibid.

Table 3-12
Biomass Capacities

Facility Type	Total State MW Capacity[21]	Existing State MW Capacity[22]	Existing SCAB MW Capacity[23]
Direct Combustion	602		
Landfill Gas	305	244	143.9
Wastewater	65	46.810	26.490
Animal Food Waste	3	3	1.660

HAZARDS AND HAZARDOUS MATERIALS

The reduction of NOx, emissions pursuant to the proposed amendments to PAR 1110.2 may affect the use, storage and transport of hazards and hazardous materials. New (or modifications to existing) air pollution control equipment (e.g., SCRs) and related components are expected to be installed at some of the affected facilities such that their operations may increase the quantity of hazardous materials (e.g., spent catalyst modules) generated by the control equipment and may increase the quantity of ammonia used. The primary effects of the proposed amendments to PAR 1110.2 with respect to hazards and hazardous materials are the anticipated overall increase in the amount of ammonia injected into SCR units for controlling NOx emissions from ICEs, the increase of ammonia slip emissions, and the increase of spent catalyst.

Ammonia is the primary hazardous chemical identified with the proposed project. Ammonia, though not a carcinogen, can have chronic and acute health impacts. Therefore, an increase in the use of ammonia in response to the proposed project may increase the current existing risk setting associated with deliveries (i.e., truck and road accidents) and onsite or offsite spills for each of the facilities that currently use or will begin to use ammonia. Exposure to a toxic gas cloud is the potential hazard associated with this type of control equipment. A toxic gas cloud is the release of a volatile chemical such as anhydrous ammonia that could form a cloud and migrate off-site, thus exposing individuals. Anhydrous ammonia is heavier than air such that when released into the atmosphere, would form a cloud at ground level rather than be dispersed "Worst-case" conditions tend to arise when very low wind speeds coincide with the accidental release, which can allow the chemicals to accumulate rather than disperse. Though there are facilities that may be affected by the proposed rule amendments and that are currently permitted to use anhydrous ammonia, for new construction, however, current SCAQMD policy no longer allows the use of anhydrous ammonia. Instead, to minimize the hazards associated with ammonia used in the SCR process, aqueous ammonia, 19 percent by volume, is typically required as a permit condition associated with the installation of SCR equipment for the following reasons: 1) 19 percent aqueous ammonia does not travel as a dense gas like anhydrous ammonia; and, 2) 19 percent aqueous ammonia is not on any acutely hazardous material lists unlike anhydrous ammonia or aqueous ammonia at higher percentages.

In addition, the shipping, handling, storage, and disposal of hazardous materials inherently poses a certain risk of a release to the environment. Thus, the routine transport of hazardous

[21] CEC, A Preliminary Roadmap for the Development of Biomass in California CEC 5000-2006-095-D, Dec 2006.
[22] California Biomass Collaborative, California Biomass Facilities Reporting System (BFRS), http://biomass.ucdavis.edu/pages/report_system.htm, June 2007.
[23]California Biomass Collaborative, June 2007, ibid.

materials, use, and disposal of hazardous materials may increase as a result of implementing the proposed project. Further, if the control option chosen by each affected facility is to install SCR, the proposed project may alter the transportation modes for feedstock and products to/from the existing facilities such as aqueous ammonia and catalyst.

Commercial catalysts used in SCRs are comprised of a base material of titanium dioxide (TiO_2) that is coated with either tungsten trioxide (WO_3), molybdic anhydride (MoO_3), vanadium pentoxide (V_2O_5), or iron oxide (Fe_2O_3). The key hazards associated with the proposed project are the crushing of the spent catalyst and transporting it for disposal or recycling. With respect to hazards and hazardous materials, this means that there will be an increase in the frequency of truck transportation trips to remove the spent catalyst as hazardous materials or hazardous waste from each affected facility. However, facilities that have existing catalyst-based operations currently recycle the catalysts blocks, in lieu of disposal. Moreover, due to the heavy metal content and relatively high cost of catalysts, recycling can be more lucrative than disposal. Thus, facilities that have existing SCR units and choose to employ additional SCR equipment to comply with the proposed amendments to PAR 1110.2, in most cases already recycle the spent catalyst and subsequently may continue to do so with the additional catalyst that may be needed.

Although recycling may be the more popular consideration, it is possible that facilities may choose to dispose of the spent catalyst in a landfill. The composition and type of the catalyst will determine the type of landfill that would be eligible to handle the disposal. For example, catalysts with a metal structure would be considered a metal waste, like copper pipes, and not a hazardous waste. Therefore, metal structure catalysts would not be a regulated waste requiring disposal in a Class I landfill unless it is friable or brittle. As ceramic-based catalysts contain a fiber-binding material, they are not considered friable or brittle and thus, would not be a regulated waste requiring disposal in a Class I landfill. Furthermore, typical catalyst materials are not considered to be water soluble, which also means they would not require disposal in a Class I landfill. In both cases, spent catalyst would not require disposal in a Class I landfill.

Based on the above information, it is likely that spent catalysts would be considered a “designated waste,” which is characterized as a non-hazardous waste consisting of, or containing pollutants that, under ambient environmental conditions, could be released at concentrations in excess of applicable water objectives, or which could cause degradation of the waters of the state (California Code of Regulations, Title 23, Chapter 3 Subparagraph 2522(a)(1)). Depending on its actual waste designation, spent catalysts would likely be disposed of in a Class II landfill or a Class III landfill that is fitted with liners.

Disposal of spent catalyst would typically involve crushing the material and encasing it in concrete prior to disposal. Since it is expected that most spent catalysts will be recycled and regenerated, it is anticipated that there will be sufficient landfill capacity in the district to accommodate disposal of any spent catalyst materials

A number of physical or chemical properties may cause a substance to be hazardous, including toxicity (health), flammability, reactivity, and any other specific hazard such as corrosivity or radioactivity. Based on a hazard rating from 0 to 4 (0 = no hazard; 4 = extreme hazard) located on the Material Safety Data Sheet (MSDS) the hazard rating for silica/alumina catalyst, for example, health is rated 1 (slightly hazardous), flammability is rated 0 (none) and reactivity is rated 0 (none). However, if nickel is deposited on the catalyst, the hazard rating is 2 for health (moderately toxic), 4 (extreme fire hazard) for flammability, 1 for reactivity (slightly hazardous if heated or exposed to water). The particular composition of the catalyst used in the SCR units, combined with the metals content of the flue gas will determine the hazard rating and whether the spent catalyst is considered a hazardous material or hazardous waste. This distinction is important because a spent catalyst that qualifies as a hazardous material could be recycled or reused by another industry (such as manufacturing California Portland cement). However, spent catalyst that is considered hazardous waste must be disposed of in a Class III landfill.

The use, storage and transport of hazardous materials are subject to numerous laws and regulations at all levels of government. The most relevant existing hazardous materials laws and regulations include hazardous materials management planning, hazardous materials transportation, hazardous materials worker safety requirements, hazardous waste handling requirements and emergency response to hazardous materials and waste incidents. Potential risk of upset is a factor in the production, use, storage and transportation of hazardous materials. Risk of upset concerns is related to the risks of explosions or the release of hazardous substances in the event of an accident or upset conditions.

Hazardous Materials Management Planning

State law requires detailed planning to ensure that hazardous materials are properly handled, used, stored, and disposed of to prevent or mitigate injury to health or the environment in the event that such materials are accidentally released. Federal laws, such as the Emergency Planning and Community-Right-to-Know Act of 1986 (also known as Title III of the Superfund Amendments and Reauthorization Act or SARA, Title III) impose similar requirements. These requirements are enforced by the California Office of Emergency Services.

The Hazardous Materials Release Response Plans and Inventory Law of 1985 (Business Plan Act) requires that any business or government agency that handles hazardous materials prepare a business plan, which must include the following (HSC §25504):

- details, including floor plans, of the facility and business conducted at the site;
- an inventory of hazardous materials that are handled or stored on the site;
- an emergency response plan; and
- a training program in safety procedures and emergency response for new employees, and an annual refresher course in the same topics for all employees.
-

Hazardous Materials Transportation

The United States Department of Transportation (DOT) has the regulatory responsibility for the safe transportation of hazardous materials between states and to foreign countries. DOT regulations govern all means of transportation, except for those packages shipped by mail, which are covered by the United States Postal Service (USPS) regulations. DOT regulations are contained in the Code of Federal Regulations, Title 49 (49 CFR); USPS regulations are in 39 CFR.

Every package type used by a hazardous materials shipper must undergo tests which imitate some of the possible rigors of travel. While not every package must be put through every test, most packages must be able to meet the following generic test criteria: the ability to be (a) kept under running water for one-half hour without leaking; (b) dropped, fully loaded, onto a concrete floor; (c) compressed from both sides for a period of time; (d) subjected to low and high pressure; and (e) frozen and heated alternately.

Common carriers are licensed by the California Highway Patrol (CHP) pursuant to the California Vehicle Code, §32000, which requires licensing of every motor (common) carrier who transports, for a fee, in excess of 500 pounds of hazardous materials at one time and every carrier, if not for hire, who carries more than 1,000 pounds of hazardous material of the type requiring placards. Common carriers conduct a large portion of their business in the delivery of hazardous materials.

Under the federal Resource Conservation and Recovery Act (RCRA) of 1976, the EPA set standards for transporters of hazardous waste. In addition, the State of California regulates the transportation of hazardous waste originating or passing through the state; state regulations are contained in the California Code of Regulations (CCR), Title 13. Hazardous waste must be regularly removed from generating sites by licensed hazardous waste transporters. Transported materials must be accompanied by hazardous waste manifests.
Two state agencies have primary responsibility for enforcing federal and state regulations and responding to hazardous materials transportation emergencies: the CHP and the California Department of Transportation (Caltrans).

The CHP enforces hazardous materials and hazardous waste labeling and packing regulations that prevent leakage and spills of material in transit and provide detailed information to cleanup crews in the event of an accident. Vehicle and equipment inspection, shipment preparation, container identification, and shipping documentation are all part of the responsibility of CHP, which conducts regular inspections of licensed transporters to assure regulatory compliance. Caltrans has emergency chemical spill identification teams at 72 locations throughout the state.

Hazardous Material Worker Safety Requirements

The California Occupational Safety and Health Administration (Cal/OSHA) and the Federal Occupational Safety and Health Administration (Fed/OSHA) are the agencies responsible for assuring worker safety in the handling and use of chemicals in the workplace. In California, Cal/OSHA assumes primary responsibility for developing and enforcing workplace safety regulations.

Under the authority of the Occupational Safety and Health Act of 1970, Fed/OSHA has adopted numerous regulations pertaining to worker safety (contained in 29 CFR – Labor). These regulations set standards for safe workplaces and work practices, including the reporting of accidents and occupational injuries. Some OSHA regulations contain standards relating to hazardous materials handling, including workplace conditions, employee protection requirements, first aid, and fire protection, as well as material handling and storage. Because California has a federally-approved OSHA program, it is required to adopt regulations that are at least as stringent as those found in 29 CFR.

Cal/OSHA regulations concerning the use of hazardous materials in the workplace (which are detailed in CCR, Title 8) include requirements for employee safety training, availability of safety equipment, accident and illness prevention programs, hazardous substance exposure warnings, and emergency action and fire prevention plan preparation. Cal/OSHA enforces hazard communication program regulations, which contain training and information requirements, including procedures for identifying and labeling hazardous substances as well as communicating hazard information related to hazardous substances and their handling. The hazard communication program also requires that Material Safety

Data Sheets (MSDSs) be available to employees and that employee information and training programs be documented. These regulations also require preparation of emergency action plans (escape and evacuation procedures, rescue and medical duties, alarm systems, and emergency evacuation training).

Both federal and state laws include special provisions for hazard communication to employees in research laboratories, including training in chemical work practices. The training must include methods in the safe handling of hazardous materials, an explanation of MSDSs, use of emergency response equipment and supplies, and an explanation of the building emergency response plan and procedures.

Chemical safety information must also be available. More detailed training and monitoring is required for the use of carcinogens, ethylene oxide, lead, asbestos, and certain other chemicals listed in 29 CFR. Emergency equipment and supplies, such as fire extinguishers, safety showers, and eye washes, must also be kept in accessible places. Compliance with these regulations reduces the risk of accidents, worker health effects, and emissions.

National Fire Codes (NFC), Title 45 (published by the National Fire Protection Association) contains standards for laboratories using chemicals, which are not requirements, but are generally employed by organizations in order to protect workers. These standards provide basic protection of life and property in laboratory work areas through prevention and control of fires and explosions, and also serve to protect personnel from exposure to non-fire health hazards.

While NFC Standard 45 is regarded as a nationally recognized standard, the *California Fire Code* (24 CCR) contains state standards for the use and storage of hazardous materials and special standards for buildings where hazardous materials are found. Some of these regulations consist of amendments to NFC Standard 45. State Fire Code regulations require emergency pre-fire plans to include training programs in first aid, the use of fire equipment, and methods of evacuation.

Hazardous Waste Handling Requirements

The RCRA created a major new federal hazardous waste regulatory program that is administered by the EPA. Under RCRA, the EPA regulates the generation, transportation, treatment, storage, and disposal of hazardous waste from "cradle to grave."

RCRA was amended in 1984 by the Hazardous and Solid Waste Act (HSWA), which affirmed and extended the "cradle-to-grave" system of regulating hazardous wastes. HSWA specifically prohibits the use of certain techniques for the disposal of some hazardous wastes.

Under RCRA, individual states may implement their own hazardous waste programs in lieu of RCRA as long as the state program is at least as stringent as federal RCRA requirements. The EPA approved California's program to implement federal regulations as of August 1, 1992.

The Hazardous Waste Control Law (HWCL) is administered by the California Environmental Protection Agency Department of Toxic Substance Control (DTSC). Under HWCL, DTSC has adopted extensive regulations governing the generation, transportation, and disposal of hazardous wastes. HWCL differs little from RCRA; both laws impose "cradle to grave" regulatory systems for handling hazardous wastes in a manner that protects human health and the environment. Regulations implementing HWCL are generally more stringent than regulations implementing RCRA.

Regulations implementing HWCL list over 780 hazardous chemicals as well as 20 to 30 more common materials that may be hazardous; establish criteria for identifying, packaging and labeling hazardous wastes; prescribe management practices for hazardous wastes; establish permit requirements for hazardous waste treatment, storage, disposal and transportation; and identify hazardous wastes that cannot be disposed of in landfills.

Under both RCRA and HWCL, hazardous waste manifests must be retained by the generator for a minimum of three years. Hazardous waste manifests list a description of the waste, its intended destination and regulatory information about the waste. A copy of each manifest must be filed with DTSC. The generator must match copies of hazardous waste manifests with certification notices from the treatment, disposal, or recycling facility.

Emergency Response to Hazardous Materials and Wastes Incidents

Pursuant to the Emergency Services Act, the State has developed an Emergency Response Plan to coordinate emergency services provided by federal, state, and local government agencies and private persons. Response to hazardous materials incidents is one part of this plan. The Plan is administered by the state Office of Emergency Services (OES), which coordinates the responses of other agencies including EPA, CHP, the Department of Fish and Game, the Regional Water Quality Control Board (RWQCB), and local fire departments. (See *California Government Code* §8550.)

In addition, pursuant to the Hazardous Materials Release Response Plans and Inventory Law of 1985 (the Business Plan Law), local agencies are required to develop "area plans" for response to releases of hazardous materials and wastes. These emergency response plans depend to a large extent on the business plans submitted by persons who handle hazardous materials. An area plan must include pre-emergency planning of procedures for emergency response, notification and coordination of affected government agencies and responsible parties, training, and follow-up.

SOLID WASTE

The Hazardous Materials Transportation Act is the federal legislation regulating the trucks that transport hazardous wastes. The primary regulatory authorities are the U.S. DOT, the Federal Highway Administration, and the Federal Railroad Administration. The Hazardous Materials Transportation Act requires that carriers report accidental releases of hazardous materials to the Department of Transportation at the earliest practicable moment (49 CFR Subchapter C, Part 171).

The DTSC is responsible for the permitting of transfer, disposal, and storage facilities. The Department of Toxic Substances Control conducts annual inspections of hazardous waste facilities. Other inspections can occur on an as-needed basis.

Caltrans sets standards for trucks transporting hazardous wastes in California. The regulations are enforced by the CHP. Trucks transporting hazardous wastes are required to maintain a hazardous waste manifest. The manifest is required to describe the contents of the material within the truck so that wastes can readily be identified in the event of a spill.

With regard to solid non-hazardous wastes, the California Integrated Waste Management Act of 1989 (AB 939), as amended, requires each county to prepare a countywide siting element which identifies how the county and the cities within the county will address the need for 15 years of disposal (landfill and/or transformation i.e., waste-to energy facilities) capacity to safely handle solid waste generated in the county, which remains after recycling, composting, and other waste diversion activities. AB 939 has recognized that landfills and transformation facilities are necessary components of any integrated solid waste management system and an essential component of the waste management hierarchy. AB 939 establishes a hierarchy of waste management practices in the following order and priority: (1) source reduction; (2) recycling and composting; and (3) environmentally safe transformation/land disposal.

Solid Waste Management

Permit requirements, capacity, and surrounding land use are three of the dominant factors limiting the operations and life of landfills. Landfills are permitted by the local enforcement agencies with concurrence from the California Integrated Waste Management Board (CIWMB). Local agencies establish the maximum amount of solid waste which can be received by a landfill each day and the operational life of a landfill. Landfills are operated by both public and private entities[24]. Landfills in the district are also subject to requirements of the SCAQMD as they pertain to gas collection systems, dust and nuisance impacts.

Landfills throughout the region typically operate between five and seven days per week. Landfill operators weigh arriving and departing deliveries to determine the quantity of solid waste delivered. At landfills that do not have scales, the landfill operator estimates the quantity of solid waste delivered (e.g., using aerial photography). Landfill disposal fees are determined by local agencies based on the quantity and type of waste delivered. Fees vary by landfill and county.

A total of 25 Class III active landfills and two transformation facilities are located within the district. Based on a search of the California Integrated Waste Management Board's Solid Waste Information System (SWIS) on May 16, 2007, there are approximately 750,846,000 cubic yards (1,250,367,507 tons) of remaining capacity at Class II and III facilities in Los Angeles, Orange County, Riverside and San Bernardino that accept construction waste.

Hazardous Waste Management

Hazardous material, as defined in 40 CFR 261.20 and 22 CCR Article 9, is disposed of in Class I landfills. California has enacted strict legislation for regulating Class I landfills. The California Health and Safety Code requires Class I landfills to be equipped with liners, a leachate collection and removal system, and a ground water monitoring system. There are no hazardous waste disposal sites within the jurisdiction of the SCAQMD.

Hazardous waste generated at area facilities, which is not reused on-site, or recycled offsite, is disposed of at a licensed in-state hazardous waste disposal facility. There are three Class I landfills in California: Chemical Waste Management Kettleman Hills in Kettleman City, CA; Clean Harbors Buttonwillow in Buttonwillow, CA or Clean Harbors Westmorland in Westemorland, CA. Chemical Waste Management Kettleman Hills has a remaining capacity of 7,360,000 cubic yards with an estimated closure date of 2037. Clean Harbors

[24] CIWMB, Used Oil Facts, 2007.

Buttonwillow and Westmorland have a remaining capacity of 12,731,000 cubic yards with an estimated closure date of 2036.

CHAPTER 4

ENVIRONMENTAL IMPACTS

INTRODUCTION

The state CEQA Guidelines require environmental documents to identify significant environmental effects that may result from a proposed project [CEQA Guidelines §15126.2(a)]. Direct and indirect significant effects of a project on the environment should be identified and described, with consideration given to both short- and long-term impacts. The discussion of environmental impacts may include, but is not limited to, the resources involved; physical changes; alterations of ecological systems; health and safety problems caused by physical changes; and other aspects of the resource base, including water, scenic quality, and public services. If significant adverse environmental impacts are identified, the CEQA Guidelines require a discussion of measures that could either avoid or substantially reduce any adverse environmental impacts to the greatest extent feasible [CEQA Guidelines §15126.4].

State CEQA Guidelines indicate that the degree of specificity required in a CEQA document depends on the type of project being proposed [CEQA Guidelines §15146]. The detail of the environmental analysis for certain types of projects cannot be as great as for others. For example, the environmental document for projects, such as the adoption or amendment of a comprehensive zoning ordinance or a local general plan, should focus on the secondary effects that can be expected to follow from the adoption or amendment, but the analysis need not be as detailed as the analysis of the specific construction projects that might follow. As a result, this ~~Draft~~Final EA analyzes impacts on a regional level and impacts on the level of individual industries or individual facilities only where feasible.

The categories of environmental impacts to be studied in a CEQA document are established by CEQA [Public Resources Code, §21000 et seq.], and the CEQA Guidelines, as promulgated by the State of California Secretary of Resources. Under the state CEQA Guidelines, there are approximately 17 environmental categories in which potential adverse impacts from a project are evaluated. Projects are evaluated against the environmental categories in an Environmental Checklist and those environmental categories that may be adversely affected by the proposed project are further analyzed in the appropriate CEQA document.

POTENTIAL ENVIRONMENTAL IMPACTS AND MITIGATION MEASURES

Pursuant to CEQA, an Initial Study, including an environmental checklist, was prepared for this project (see Appendix D) and circulated along with an NOP/IS for a 30-day public review period. Of the 17 potential environmental impact categories, four (air quality, energy, hazards and hazardous material, and solid/hazardous waste) were identified as being potentially significantly adversely affected by the proposed project. During the public comment period SCAQMD received two comment letters on the NOP/IS. The comment letters and individual responses to comments in each comment letter are included in Appendix E.

As already indicated, the following environmental topic areas: air quality, hazards and hazardous material, and solid/hazardous waste were identified in the NOP/IS as areas that could potentially be adversely affected by the proposed project and are comprehensively analyzed further in this EA. Aesthetics and energy impacts are also evaluated in this EA based on comments received during the public review period for the NOP/IS. The environmental impact analysis for each environmental topic typically incorporates a "worst-case" approach. This approach entails the premise that whenever the analysis requires that assumptions be made, those assumptions that result in the greatest adverse impacts are typically chosen. In some instances the "worst-case" assumption may not be feasible or possible. In this situation, additional assumptions are made such that reasonable "worst-case" assumptions are assumed for the analysis. This process ensures that all potential effects of the proposed project are documented for the decision-makers and the public.

Accordingly, the following analyses use a reasonable "worst-case" approach for analyzing the potentially significant adverse environmental impacts associated with the implementation of the proposed project.

New Projects

PAR 1110.2 includes requirements for new ICEs. PAR 1110.2 requires that new stationary, non-emergency generators must meet the CARB 2007 standards (Distributed Generation Certification Program, Article 3, Subchapter 8, Chapter 1, Division 30, Title 17 for the California Code of Regulations. These standards have been in effect since January 1, 2007. Other new ICEs would need to meet emissions standards which are already required by the existing rule or BACT which is already required for new equipment. New equipment may need additional monitoring and reporting equipment; however the installation of new monitoring and reporting equipment should have minor environmental impacts compared to the installation of the new ICE. Operators/owners that install new ICEs for any other reason than to replace existing ICEs to comply with PAR 1110.2 are outside the scope of this proposed project. New engines would be required to enter the permit process before construction. All permitted equipment is required to have a CEQA evaluation. Impacts from the construction of new engines would be evaluated at that time. Adverse impacts from the new project will be evaluated during the CEQA review during permitting.

Since operators/owners have other options beside ICEs, such as fuel cells, boilers, gas turbines, microturbines, etc., it is speculative to assess the environmental adverse impacts from future new projects in this document. Therefore, no further analysis of new projects has been prepared for this project.

Changes to PAR 1110.2 Since the Release of the Draft EA for Public Review

Additional Exceptions

To give operators some additional flexibility, the 10 percent natural gas condition was modified to be based on the facility average rather than for each engine. Several biogas engine operators commented on PAR 1110.2 stating that the 10 percent limit could lead to increased flaring of biogas. One said it could cause a blower engine to shut down, resulting in more flaring of digester gas. Another said that at times there might be insufficient digester gas to run an engine at the minimum load necessary for operation stable operation and with emissions in compliance with permit limits. Another said that some natural gas may be needed in the future if the heating value of landfill gas declines to a level below that needed for proper engine operation.

Another sewage treatment plant operator reported that the 10 percent limit would force a reduction in engine load, and reduce the thermal energy recovered by their waste heat boiler that provides heat to their digesters. At times, the recovered waste heat would not be enough to operate the digesters, and the facility does not have boilers to back up or supplement the engines. The facility operator estimates that three months out of the year more than 10 percent natural gas would be required.

PAR 1110.2 authorizes the Executive Officer (EO) to approve more than 10 percent natural gas in these limited situations. Operators must apply for a change of permit conditions and demonstrate the need for the additional natural gas. The EO will evaluate each case and put appropriate conditions on each permit that will allow the additional natural gas use, but only under conditions when it is deemed necessary.

PAR 1110.2 allows operators to exclude from the calculation of the natural gas percentage the natural gas used in a few situations. One operator asked to be able to use more than 10 percent natural gas when rainy weather causes the sewage treatment plant to operate above its design capacity, requiring the highest use of electrical power for pumps and other equipment. During rainy weather, air quality is at its best and the impact of the higher emissions should be minimal.

The same operator said that plant reliability would be improved if they could increase engine loads, with more natural gas use, when grid electric power is short and rolling brownouts are likely. Allowing this during Stage 2 electrical emergencies has other emission benefits. If the brownout does occur at the facility, the plant's backup diesel generators, which have much higher emissions than the biogas engines, would not have to provide as much of the facility's power requirement, and overall emissions would be reduced. Also, by increasing electrical power output during the Stage 2, brownouts might even be avoided, which prevents widespread backup diesel generator use.

A commenter on PAR 1110.2 stated that lean-burn and RELCAIM engines meet the 2,000 ppm CO limit without oxidation catalyst. An exception from the quarterly CO monitoring was added for diesel and other lean-burn engines that are subject or Regulation XX or have a NOx CEMs and that are not subject to a CO limit more stringent than 2,000 ppm. The engines would still be subject to the I&M plans.

Standards for New Distributed Generation Equipment

Staff originally proposed emission standards that, as of January 1, 2007, CARB already enforce the above standards for distributed generation equipment that do not require local district permits. The CARB standards are based on the emissions from large new central generating stations with BACT. Since large and small electrical generators are already required to meet these standards, the proposed standards will simply extend the same requirements ICEs that require SCAQMD permits. This was the goal of SB1298 as previously described in Chapter 1. However, the Engine Manufacturers Association commented that by increasing the proposed limits, in lbs/MW-hr, from 0.10 to 0.20 for CO and from 0.02 to 0.10 for VOC, some advanced engines may be able to comply.

Analysis of New Changes to PAR 1110.2

Emergency and Rainy Day Exemptions

The new exceptions to the monthly 10 percent requirement were added to address either emergency operations or extremes in weather. Since emergencies and extremes in weather cannot be predicted, adverse impacts from these changes are considered to be speculative and will not be addressed in the Final EA.

Exception for ICEs That Are Used to Heat Digesters

Emission increases for facility that would need to run more than 10 percent natural gas over three months a year to supplement heat to the digesters were estimated and presented in Table 4-0a. Detailed calculations can be found at the end of Appendix C. Table 4-0b shows that the additional emissions from the exception for ICEs that are used to heat digesters would not increase criteria pollutants that are less than significant to become significant. PM2.5 was determined to be significant in the Draft EA. The additional PM2.5 from the waste heat boiler would increase project PM2.5 emissions by approximately one pound. The additional PM2.5 increase is less than the SCAQMD CEQA threshold of 55 pounds per day. Therefore, the additional PM2.5 emissions are not considered a substantial increase in the severity of an adverse environmental impact that would require recirculation. The additional emissions have been added to the emission tables in the air quality section.

Table 4-0a
Summary of Exception for Natural Gas for Waste Heat Recovery Boilers

Description	NOx Emissions, lb/day	CO Emissions, lb/day	VOC Emissions, lb/day	SOx Emissions, lb/day	PM10 Emissions, lb/day	PM2.5 Emissions, lb/day
ICE	5.41	32.85	8.84	0.6	0.88	0.87

Table 4-0b
Update to Proposed Project Emissions

Description	NOx Emissions, lb/day	CO Emissions, lb/day	VOC Emissions, lb/day	SOx Emissions, lb/day	PM10 Emissions, lb/day	PM2.5 Emissions, lb/day
Boiler Exception	5.41	32.85	8.84	0.6	0.88	0.87
Significance Threshold	55	550	75	150	150	55
Significant or Substantial Increase?	No	No	No	No	No	No*

Quarterly Monitoring Exemption

SCAQMD staff believes that lean-burn engines that are subject or Regulation XX or have a NOx CEMs would meet the 2,000 ppm CO emissions limit. Even though an exception from quarterly monitoring was added, operators would still need to prepare an I&M plan for these engines. The I&M plan will assist operators with finding engine malfunctions and to correct air-to-fuel ratios to assure proper engine operation, which will reduce emissions.

Revision to the New Engine Emission Requirements

The use of new CARB 2007 Distributed Generated Certification compliant engines was not expected to generate any greater adverse impacts than new distributed generators that are compliant with the existing Rule 1110.2 and BACT, with the exception of air quality. CARB 2007 Distributed Generated Certification compliant engines would generate less NOx, VOC and CO. That is, new CARB 2007 Distributed Generated Certification compliant engines are expected to look similar to new engines that are compliant with the existing Rule 1110.2 with BACT, use similar amounts of energy, generate similar amounts of wastes, and generate similar off-site accidental releases. The choice of installation of one new engine over another would not affect any agricultural resources, biological resources, cultural resources, hydrology/water quality, geology/soil, land use/planning, mineral resources, noise, population/housing, public services, recreation or transportation/traffic.

The revision of CO and VOC limits would still achieve the same NOx reductions as the original proposal, and for an electrical generator without heat recovery, the revised limits will still achieve an 89 percent reduction of CO and a 77 percent reduction of VOC, compared to the current BACT limits for typical new engines. Even though SCAQMD is in attainment for CO, the CO limit is still necessary because CO contributes to ozone formation and it is a good indicator of catalyst performance, and unlike VOC, can be easily monitored by a CEMS or a portable analyzer. In addition, the number of new distributed engines is unknown and therefore adverse impacts from these engines were considered speculative and not evaluated in the Final EA.

Aesthetics

In the NOP, SCAQMD staff stated that PAR 1110.2 would not require any new development, but may require minor modifications to buildings or other structures for retrofit or replacement. Operators at commercial and industrial facilities may install new, retrofit or replace existing ICEs, control technologies, and/or monitoring equipment. The equipment would be placed within the boundaries of existing commercial or industrial facilities near existing ICE systems. The NOP/IS concluded that installation of retrofit control equipment such as oxidation catalyst systems, for example, would not be substantially different in appearance than existing muffler systems. A CEMS equipment housing may need to be built to protect the system from the weather and, therefore, would not be substantially different in physical appearance than the other existing commercial or industrial equipment at these facilities. It was concluded that because retrofitted, replaced and/or new equipment would not be substantially different in size in appearance than existing equipment the proposed project would not obstruct scenic resources or degrade the existing visual character of a site, including but not limited to: trees, rock outcroppings, or historical buildings.

Subsequent to the release of the NOP/IS, it was determined that operators of some biogas facilities may choose to replace ICEs with biogas to LNG facilities, gas turbines, microturbines, boilers or fuel cells. These types of equipment could change the visual character of the affected facilities, thus, potentially creating adverse aesthetics impacts. This potential impact is evaluated in the "Biogas Facilities" discussion below.

Significance Criteria

The proposed project impacts on aesthetics will be considered significant if:

- The project will block views from a scenic highway or corridor.
- The project will adversely affect the visual continuity of the surrounding area.
- The impacts on light and glare will be considered significant if the project adds lighting which would add glare to residential areas or sensitive receptors.

Non-Biogas Engines – New, Retrofit or Replacement Equipment

The conclusions in the NOP/IS still apply to operators of affected engines who choose to retrofit, replace or add new equipment to existing non-biogas ICE engines. Retrofitted engines would not create significant adverse aesthetics impacts since these equipment would be similar in size and character to existing engines.

Non-Biogas Engines – Replacement with Electric Motors and Emergency ICE

As part of the CEQA analysis, based on cost estimates SCAQMD staff identified 225 non-biogas engines where operators would incur lower compliance costs if they replaced existing ICEs with electric motors instead of incurring the costs of installing emissions controls and monitoring and inspection and maintenance (I&M) equipment that would be necessary to comply with PAR 1110.2. Compliance cost calculations are included in Appendix C. Not all operators with non-biogas engines would replace existing ICEs with electric motors based solely on cost considerations. Therefore, SCAQMD staff assumed that operators of 75 percent of the non-biogas engines that may have cost savings (169 engines) would be voluntarily replaced their existing engines with electric motors. It is assumed that 40 percent of these existing engines would be used as emergency backup generators. Twenty percent would use diesel-fueled emergency backup engines. It is assumed that the remaining 40 percent would not need an emergency backup engine.

The conclusions in the NOP/IS still apply to operators of affected engines who choose to replace non-biogas engines with electric motors. Electric motors would likely be placed at or near the location of the existing ICE that would be removed. If the existing engine is used as an emergency backup engine, then it is assumed it would not be moved. It is assumed that if a new diesel emergency engine is installed it would be near the location of the existing ICE engine that would be removed. Since affected non-biogas facilities would already have an existing ICE, it is not expected that the replacement of the ICE with an electric motor and installation of a new emergency backup diesel engine or the use of the existing engine as an emergency backup engine for a new electric motor would change the visual character of the affected facility.

Biogas Engines – New, Retrofit or Replacement Equipment

With the exception of ducting, add-on control systems are expected to be low in profile and height, and not visible to the surrounding area due to existing fencing along the property lines. Existing structures currently within the facilities may buffer the view of such proposed equipment. Systems that require ammonia or urea such as SCR and NOxTech systems may create a more industrial appearance, if located near facility boundaries. The

SCR and NOxTech systems may be as large as the ICEs that they control and may also be visible from outside the facility if placed near the fence line. At digester gas facilities and operating landfills, these systems may not alter the visual character of the area. At closed landfills, these systems may alter the visual character of the area, thus, adversely affecting the visual continuity of the surrounding area.

Therefore, since SCR and NOxTech systems at closed landfills may alter the visual character of the surrounding areas, PAR 1110.2 may create significant adverse aesthetic impacts at biogas facilities due to the installation of retrofit technologies.

Biogas Engines – Replacement Technologies

Biogas facility operators may choose to replace existing ICEs with biogas to LNG facilities, gas turbines, microturbines, fuel cells or boilers. Turbines, microturbines, fuel cells, and boilers are similar in physical characteristics to existing ICE systems. It is unlikely that replacing ICEs with any one of these technologies would modify the visual characteristics of the existing facilities since they are similar in visual character to the ICEs they would be replacing.

The installation of a biogas to LNG facility would require approximately three acres of land based on the existing LNG facility at the Frank R. Bowerman Landfill in Orange County. The biogas facility would consist of process equipment, storage tanks and truck loading racks. Because of the size of the biogas to LNG facility, process equipment and truck loading racks, the equipment and truck loading operations may be visible from outside of the facility. In addition, the process equipment may need additional lighting. Therefore, the installation of a biogas to LNG facility may alter the visual character of the area, thus, adversely affecting the visual continuity of the surrounding area.

Therefore, since SCR and NOxTech systems at closed landfills and LNG facilities may alter the visual character of the surrounding areas, PAR 1110.2 is significant for adverse aesthetic impacts at biogas facilities.

Affected industry representatives have indicated that instead of complying with PAR 1110.2 through retrofitting existing engines, replacing them with new compliant engines, or replacing existing engines with alternative technologies they may simply replace existing engines with flares. Adding a new flare could further degrade the existing visual character of a facility, even though most biogas facilities have an existing flare as an emergency backup system. The potential installation of flares could further degrade the visual character of a biogas facility and, therefore, may create significant adverse aesthetics impacts. To prevent replacement of ICEs with flares, SCAQMD staff has committed to a technology assessment to verify that feasible control options are available to comply with PAR 1110.2 to prevent replacement of biogas ICEs with continuous flaring. If the technology assessment shows potential for flaring or that feasible control options for biogas engines are not available, staff will return to the Governing Board with a proposal to address any new significant adverse impacts. Therefore, the continuous use of new or existing flares ~~are~~ is not expected to be consequence of PAR 1110.2.

Project-Specific Mitigation Measures:

Significant adverse aesthetic impacts are only expected as a result of complying with PAR 1110.2 at biogas facilities. No specific mitigation measures were identified to reduce adverse aesthetic impacts. It is expected that facility operators would place control technology or ICE alternatives away from property boundaries. However, space issues and the location of utilities, location and quality of the biogas source, and piping may dictate the placement of equipment. Equipment may be masked by perimeter walls or landscape vegetation; although, fire prevention and safety issues would take precedence over aesthetic concerns. As a result, there is no guarantee that landscape vegetation would be available as a means of reducing aesthetics impacts.

A technology assessment will be completed in 2010 to evaluate possible control options PAR 1110.2. The technology assessment evaluate whether that feasible control options are available to comply with PAR 1110.2 to prevent replacing biogas ICEs with continuous biogas flaring. If the technology assessment shows potential for flaring or that feasible control options for biogas engines are not available, staff will return to the Governing Board with a proposal to address any new significant adverse impacts. Therefore installation of flares is not considered to be a reasonably foreseeable adverse aesthetics impact.

Since the location and type of control equipment or ICE replacement is unknown for any specific biogas facility and the effectiveness of perimeter walls and landscaping to minimize aesthetics impacts is unknown, it is assumed that aesthetics impacts cannot be mitigated to less than significant.

Remaining Aesthetic Impacts:

Since no project-specific mitigation measures were identified that could eliminate significant adverse aesthetic impacts, aesthetics impacts remain significant.

Cumulative Aesthetic Impacts:

Since project-specific adverse aesthetic impacts are significant, it is possible that cumulative aesthetic impacts from other related facilities in the vicinity of each affected biogas facility that would be subject to PAR 1110.2 could be cumulatively considerable. However, since no biogas facility is within three miles of another biogas facility, potential project-specific aesthetic impacts at more than one affected biogas facility are not perceptible, and, therefore, not considered to be cumulatively considerable as defined by CEQA Guidelines §15064(h)(1). Therefore, PAR 1110.2 is not expected to generate significant adverse cumulative aesthetics impacts.

Cumulative Aesthetic Impact Mitigation:

Because implementing PAR 11110.2 is not expected to create significant adverse cumulative aesthetic impacts, no cumulative impact mitigation measures are required.

Air Quality

Significance Criteria

To determine whether or not air quality impacts from adopting and implementing PAR 1110.2 are significant, impacts will be evaluated and compared to the following criteria. The proposed project will be considered to have significant adverse air quality impacts if any one of the thresholds in Table 4-1 are equaled or exceeded.

Table 4-1
Air Quality Significance Thresholds

Mass Daily Thresholds [a]		
Pollutant	***Construction*** [b]	***Operation*** [c]
NOx	100 lbs/day	55 lbs/day
VOC	75 lbs/day	55 lbs/day
PM10	150 lbs/day	150 lbs/day
PM2.5	55 lbs/day	55 lbs/day
SOx	150 lbs/day	150 lbs/day
CO	550 lbs/day	550 lbs/day
Lead	3 lbs/day	3 lbs/day
Toxic Air Contaminants (TACs) and Odor Thresholds		
TACs (including carcinogens and non-carcinogens)	Maximum Incremental Cancer Risk ≥ 10 in 1 million Hazard Index ≥ 1.0	
Odor	Project creates an odor nuisance pursuant to SCAQMD Rule 402	
Ambient Air Quality for Criteria Pollutants		
NO2 1-hour average annual average	SCAQMD is in attainment; project is significant if it causes or contributes to an exceedance of the following attainment standards: 0.25 ppm (state) 0.053 ppm (federal)	
PM10 24-hour average annual geometric average annual arithmetic mean	 10.4 $\mu g/m^3$ (construction) & 2.5 $\mu g/m^3$ (operation) 1.0 $\mu g/m^3$ 20 $\mu g/m^3$	
PM2.5 24-hour average	10.4 $\mu g/m^3$ (construction) & 2.5 $\mu g/m^3$ (operation)	
Sulfate 24-hour average	1 $\mu g/m^3$	
CO 1-hour average 8-hour average	SCAQMD is in attainment; project is significant if it causes or contributes to an exceedance of the following attainment standards: 20 ppm (state) 9.0 ppm (state/federal)	

[a] Source: SCAQMD CEQA Handbook (SCAQMD, 1993)
[b] Construction thresholds apply to both the South Coast Air Basin and Coachella Valley (Salton Sea & Mojave Desert Air Basins).
[c] For Coachella Valley, the mass daily thresholds for operation are the same as the construction thresholds.
KEY: lbs/day = pounds per day ppm = parts per million $\mu g/m^3$ = microgram per cubic meter ≥ greater than or equal to

Direct Impacts from Implementing PAR 1110.2 – Operation

PAR 1110.2 would reduce precursor ozone and particulate emissions from gaseous- and liquid-fueled ICEs. Table 4-2 presents the number of ICEs affected by PAR 1110.2. Table 4-3 shows baseline emissions from ICEs derived for the population of ICEs in 2005, using survey information and source test information obtained by SCAQMD staff (see Table 3-5). Table 4-3 shows the year 2005 baseline emission inventories for affected equipment categorized into non-biogas and biogas facilities.

Table 4-2
Inventory of Engines

Category	Diesel	Digester Gas	Digester/ Landfill Gas	Field Gas	Landfill Gas	Natural Gas	Propane	Survey[a] Total	Total[b]
Biogas, BACT, <1000		1						1	1
Biogas, BACT, =>1000		2			14			16	20
Biogas, Non-BACT <1000		12						12	15
Biogas, Non-BACT, =>1000		10	3		12			25	31
Non-Biogas, Non-RECLAIM, BACT, Lean, <1000						3		3	4
Non-Biogas, Non-RECLAIM, BACT, Lean, =>1000						16		16	22
Non-Biogas, Non-RECLAIM, BACT, Rich, <1000				9		238	1	248	336
Non-Biogas, Non-RECLAIM, BACT, Rich, =>1000				2		26		28	38
Non-Biogas, Non-RECLAIM, Non-BACT, Rich, <1000						181		181	245
Non-Biogas, Non-RECLAIM, Non-BACT, Rich, =>1000						5		5	7
Non-Biogas, RECLAIM, Non-BACT, Lean, Major, Diesel	6							6	6
Non-Biogas, RECLAIM, BACT, Lean, Major, Diesel	6							6	6
Non-Biogas, RECLAIM, BACT, Rich, Major				1				1	1
Non-Biogas, RECLAIM, BACT, Rich, Non-Major						16		16	20

Table 4-2 (Continued)
Inventory of Engines

Category	Diesel	Digester Gas	Digester/ Landfill Gas	Field Gas	Landfill Gas	Natural Gas	Propane	Survey[a] Total	Total[b]
Non-Biogas, RECLAIM, Non-BACT, Lean, Major						25		25	31
Non-Biogas, RECLAIM, Non-BACT, Lean, Non-Major	18			1		10		29	32
Non-Biogas, RECLAIM, Non-BACT, Rich, Major						1		1	1
Non-Biogas, RECLAIM, Non-BACT, Rich, Non-Major						36		36	44
Survey Total	30	25	3	13	26	557	1	673	1
Total	30	31	4	17	32	744	1		859

a) SCAQMD staff sent surveys out to permit holders that are affected by PAR 1110.2. The information received from these surveys was used to develop the emissions inventory for PAR 1110.2.
b) Total number of engines was estimated by scaling the surveyed engines by the number of engines in the permit database by category (biogas, non-biogas, natural gas, diesel, RECLAIM, non-RECLAIM).

Table 4-3
Estimated Year 2005 Baseline Emissions Inventory
Categorized by Non-Biogas and Biogas Facilities

Description	Number of Engines	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM*, lb/day
Non-Biogas	793	7,336	44,688	1,611	87	741
Biogas	66	1,859	9,555	882	464	136
Total	859	9,195	54,243	2,493	551	877

* Combustion PM emissions were developed from PM10 emission factors. However, combustion PM emissions are comprised mostly of PM2.5 emissions (98 to 99 percent PM2.5). PM includes both PM10 and PM2.5. PM10 includes PM2.5.

Table 4-4 shows the estimated emission reductions by year assuming that all affected engines can comply with the emission concentration requirements in PAR 1110.2 and taking into account better monitoring. The estimated emission reductions show emission reductions from the baseline year of 2005. The emission reductions do not show the effects of potential secondary quality impacts, which are analyzed later in this document.

Table 4-4
Estimated Emission Reductions by Year from the Baseline Year 2005 from Implementing PAR 1110.2

Year	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM* lb/day
2008	~~204~~ 199	~~379~~ 346	~~35~~ 26	~~8~~ 7	~~5~~ 5
2009	~~2,359~~ 2,354	~~30,936~~ 30,903	~~646~~ 637	~~8~~ 7	~~5~~ 5
2009	~~2,374~~ 2,369	~~31,709~~ 31,676	~~658~~ 649	~~8~~ 7	~~5~~ 5
2010	~~2,748~~ 2,743	~~35,929~~ 35,896	~~1,127~~ 1,118	~~10~~ 9	~~8~~ 8
2011	~~3,093~~ 3,088	~~38,845~~ 38,752	~~1,372~~ 1,165	~~0~~ 9	~~0~~ 8
2012	4,335	38,845	1,372	0	0

* Combustion PM emissions were developed from PM10 emission factors. However, combustion PM emissions are comprised mostly of PM2.5 emissions (98 to 99 percent PM2.5). PM includes both PM10 and PM2.5. PM10 includes PM2.5.

Table 4-5 shows the total emission reductions by the year 2012 for affected equipment, which is the year of full compliance with PAR 1110.2, categorized into non-biogas and biogas facilities.

Table 4-5
Estimated Emission Reductions in Year 2012 upon Full Implementation of PAR 1110.2 Categorized by Non-Biogas and Biogas Facilities

Description	Number of Engines	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM*, lb/day
Non-Biogas	793	2,948	37,383	1,045	0	0
Biogas	66	1,387	1,463	327	0	0
Total	859	4,335	38,845	1,372	0	0

* Combustion PM emissions were developed from PM10 emission factors. However, combustion PM emissions are comprised mostly of PM2.5 emissions (98 to 99 percent PM2.5). PM includes both PM10 and PM2.5. PM10 includes PM2.5.

Table 4-6 shows the estimated emission inventories by year from ICEs complying with PAR 1110.2. All emission reductions for the year 2008 are assumed to result from biogas facility operators complying with the provision in subparagraph (d)(1)(C) regarding the operation of engines on 90 percent or more of landfill or digester gas. The emission inventory estimates assume that all affected ICEs will be able to comply with the proposed emission concentration and includes the effects of the enhanced monitoring and enforcement requirements. This analysis does not pre-judge the results of the future technology assessment in 2010, which may conclude that additional time may be necessary for compliance, or different emission concentration limits are appropriate. The declining emission inventories in Table 4-6 also do not take into consideration potential secondary air quality impacts resulting from PAR 1110.2, which are analyzed later in this document.

Table 4-6
Estimated Remaining Emission by Year
Resulting from Implementing PAR 1110.2

Year	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM* lb/day
2008	~~9,195~~ 9,200	~~54,243~~ 54,276	~~2,493~~ 2,502	~~551~~ 552	~~877~~ 877
2009	~~8,991~~ 8,996	~~53,865~~ 53,898	~~2,458~~ 2,467	~~544~~ 545	~~871~~ 871
2009	~~6,836~~ 6,841	~~23,307~~ 23,340	~~1,846~~ 1,855	~~544~~ 545	~~871~~ 871
2010	~~6,820~~ 6,452	~~22,534~~ 18,347	~~1,834~~ 1,375	~~544~~ 543	~~871~~ 869
2011	~~6,447~~ 6,452	~~15,458~~ 18,347	~~1,319~~ 1,375	~~542~~ 543	~~869~~ 869
2012	4860	1,5398	1,121	551	877

* Combustion emissions where developed from PM10 emission factors. However, combustion PM emissions are comprised mostly of PM2.5 emissions (PM 10 emissions are 98 to 99 percent PM2.5).

Table 4-7 shows the year 2012 emission inventories for affected equipment, which is the year of full compliance with PAR 1110.2, categorized into non-biogas and biogas facilities.

Table 4-7
Estimated Year 2012 Emissions Remaining upon Full Implementation of PAR 1110.2
Categorized by Non-Biogas and Biogas Facilities

Description	Number of Engines	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM*, lb/day
Non-Biogas	793	4,388	7,305	566	87	741
Biogas	66	472	8,092	555	464	136
Total	859	4,860	15,398	1,121	551	877

* Combustion PM emissions were developed from PM10 emission factors. However, combustion PM emissions are comprised mostly of PM2.5 emissions (PM 10 emissions 98 to 99 percent PM2.5). PM includes both PM10 and PM2.5. PM10 includes PM2.5.

Calculating Emissions – Non-biogas Facilities

To calculate the effects of PAR 1110.2 for non-biogas engines, it was assumed that affected facility operators would install similar types of monitoring and control equipment at each facility. PAR 1110.2 specifies that CEMS, air-to-fuel ratio controllers (ATFRC), and CO analyzers would be needed. Lean burn non-RECLAIM, rich burn non-RECLAIM, and rich burn RECLAIM engines are already controlled by oxidation catalysts. Currently, the only uncontrolled non-biogas engines are lean burn RECLAIM engines. To comply with PAR 1110.2, it is expected that operators of existing uncontrolled, lean burn, RECLAIM non-biogas engines would control VOC and CO emissions through the use of an oxidation catalyst. The existing uncontrolled, lean burn, RECLAIM non-biogas engines are exempt from PAR 1110.2 NOx requirements, since NOx from these facilities is subject to RECLAIM NOx control requirements.

Emission Assumptions for Existing Equipment

Rich-burn Engines: For non-RECLAIM rich-burn engines that were originally permitted at BACT emission levels and that have NOx CEMS, it was assumed that NOx emissions are maintained on average at 80 percent of the existing Rule 1110.2 NOx emissions limit. For most rich-burn engines, baseline NOx and CO emissions were developed from NOx and CO limits multiplied by factors that are based on SCAQMD compliance test results (see Table 3-4). SCAQMD compliance tests showed that for engines without CEMS, the average ratio of measured NOx to the NOx limit is 5.19 for BACT engines (NOx limit in 8 to 23 ppm range) and 2.12 for non-BACT engines (NOx limit in 36 to 59 ppm range). Although compliance testing did not include VOC data, source test data reported in the engine survey showed that VOC levels tend to correlate to roughly the square root of the CO level.

For RECLAIM major sources, it was assumed that the NOx level is at the apparent "limit," calculated from Annual Emissions Report data. For non-BACT rich-burn engines in RECLAIM, NOx concentrations are often above the range of the SCAQMD compliance data (none tested in this category), and it is assumed that baseline NOx for non-major sources (no CEMS) in this group is maintained, on average, at the NOx limit.

Lean-burn Engines: For non-BACT lean-burn RECLAM engines, non-CEMS NOx emissions were assumed to be maintained at the reported limit or apparent limit that was calculated based on annual emission reporting. CO and VOC emissions were assumed to be 10 percent over source test results on average.

For BACT, non-RECLAIM lean-burn engines, non-CEMS NOx emissions were assumed to be 1.8 times the NOx limit based on SCAQMD compliance test results (see Table 3-4). CO and VOC emissions were assumed 10 percent above average source test results.

Emission Reduction Assumptions to Comply with PAR 1110.2

The analysis of emissions reductions from non-biogas engines to comply with PAR 1110.2 was based on the type of engine, emission limits and compliance expectations as explained in the preceding subsection. The analysis was based on a total population of 793 non-biogas engines.

For the CEQA analysis, SCAQMD staff performed a cost analysis for existing non-biogas engines comparing various cost of compliance options to the cost of complying with PAR 1110.2, i.e., the costs of installing emissions control equipment, monitoring equipment, I&M, etc., to the cost replacing existing ICEs with electric motors (calculations are included in Appendix C). The analysis indicated that the cost of replacing existing specific categories of non-biogas ICEs (225 non-biogas ICEs out of the total 793 non-biogas engines) with electric motors would be less than the cost of complying with PAR 1110.2 requirements, i.e., the cost of retrofitting the same engines with emissions control equipment, monitoring equipment I&M, etc. Table 4-8 shows the engine categories for the existing 225 engines where the cost of replacing existing ICES with electric motors would be less costly than complying with PAR 11102. However, not all operators with non-biogas engines in the engine categories shown in Table 4-8 are expected to replace existing non-biogas ICEs with electric motors based solely on cost considerations. Therefore, SCAQMD staff assumed that operators of 75 percent of the engines shown in Table 4-8 (169 engines) would choose electrification as their compliance option.

Table 4-8
Non-biogas ICE Categories Where Replacing Existing ICEs with Electric Motors Would be Less Costly Compared to Complying with PAR 1110.2 Requirements

Engine Use	Number of Engines Surveyed	Total Engines	Assumed No. of ICEs Replaced with Electric Motors
Non-Biogas, Non-RECLAIM, BACT, Lean, <1000	2	3	2
Non-Biogas, Non-RECLAIM, Non-BACT, Rich, <1000	126	170	128
Non-Biogas, RECLAIM, BACT, Rich, Non-Major	6	7	5
Non-Biogas, RECLAIM, Non-BACT, Lean, Major	15	19	14
Non-Biogas, RECLAIM, Non-BACT, Lean, Non-Major	7	9	7
Non-Biogas, RECLAIM, Non-BACT, Rich, Non-Major	14	17	13
Total	170	225	169

It was assumed that operators who install electric motors on 40 percent of the engines shown in Table 4-8 would keep their existing ICEs as emergency backup generators. It was further assumed that operators who install electric motors on 20 percent of the engines shown in Table 4-8 would purchase new diesel ICEs for emergency backup generators. Finally operators of the remaining 40 percent were assumed not to need emergency backup generators because of the nature of their operations. Emission reductions from replacing 169 existing engines with electric motors are presented in Table 4-9. Secondary emissions from the diesel emergency backup generators are analyzed later in this section.

Table 4-9
Emissions Reductions from the Compliance Option of Replacing Existing Non-Biogas ICEs with Electric Motors

NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM, lb/day	CO2, ton/year
1,044	2,507	175	14.3	87.9	107,276

- Combustion PM emissions were developed from PM10 emission factors. However, combustion PM emissions are comprised mostly of PM2.5 emissions (PM 10 emissions 98 to 99 percent PM2.5). PM includes both PM10 and PM2.5. PM10 includes PM2.5.
- This table presents only the emission reductions from replacing the non-biogas ICEs with electric motors. It does not include the secondary emissions from power plants or emergency engines.

It was assumed that operators of all 624 remaining non-biogas engines would comply with the requirements of PAR 1110.2 by installing appropriate control technologies. Total emission reductions by 2012 for non-biogas ICEs are shown in Table 4-7.

Calculating Emissions – Biogas Facilities

Biogas facilities can be categorized as either landfill gas facilities or digester gas facilities. Landfill gas facilities collect biogas from landfills and combust the biogas to generate electricity. Digester gas facilities collect biogas from water treatment facilities or compost facilities and combust the biogas to generate electricity or power compressors and pumps.

Emission Assumptions for Existing Equipment

Biogas baseline emissions are based on NOx limits, landfill gas VOC limits (40 ppm as methane at 15 percent O_2), average VOC source test results for digester gas engines based on the survey data, and average CO source test results based on the survey data. In all cases except for CEMS-monitored NOx engines, baseline emissions are assumed to be, on average, 10 percent higher than the above limits or source test results.

Emission Reduction Assumptions to Comply with PAR 1110.2

It is assumed that operators of biogas systems will comply with PAR 1110.2 by controlling emissions from ICEs with SCR or NOxTech systems or replace the ICE with an alternative technology that would not be regulated by PAR 1110.2, such as, boilers, gas turbines, microturbines, fuel cells or biogas to LNG facilities[25]. Emission reductions from ICEs controlled by SCR or NOxTech systems were estimated based on PAR 1110.2 limits. The emission reductions anticipated for PAR 1110.2 are based on the assumption that operators of biogas facilities can comply with PAR 1110.2 by installing control equipment onto their equipment. However, based on comments received by the regulated industry, operators may replace biogas engines with alternative technologies and, thus, would no longer be subject to PAR 1110.2. If biogas operators choose to replace ICEs with alternative technologies (gas turbines, microturbines, LNG plants, etc.), the alternative technologies would be subject to other regulatory requirements such as Regulation XIII.

To account for the possibility that affected operators may install alternative technologies; staff has calculated the potential emission reduction effects if all affected biogas engines are replaced with alternative technologies. Table 4-10 shows the emission factors used to calculate the emission reduction effects for ICEs, boilers, gas turbines and microturbines. To address concerns of commenters, which have not been verified, SCAQMD staff has committed to a technology assessment in 2010. If the technology assessment shows the potential for flaring, then staff will return to the Governing Board with a proposal addressing any new significant adverse impacts. Facility operators who replace ICEs with fuel cells would not generate any appreciable emissions, so emissions would essentially be zero. The analysis assumes that facility operators who replace ICEs with biogas to LNG facilities would generate emissions from boilers used to produce heat for the process and would use electric motors for electricity.

[25] ICE alternative technologies are included here based on comments received at PAR 1110.2 working group meetings. Further, LNG derived from biogas would be pretreated for sale offsite or used onsite as natural gas.

Table 4-10
Emission Factors (lb/MMBtu) for Biogas Facility Control Options

Pollutant	ICE	Boiler	Gas Turbine	Microturbine
NOx	0.127	0.03	0.084	0.012
CO	0.644	0.0041	0.139	0.047
VOC	0.041	0.0034	0.0048	0.012
PM	0.013	0.0092	0.023	0.0037

NOx, CO, VOC and PM emissions were based on averages of source test data in AQMD files.
SOx was estimated from the fuel digester gas - 40 ppm as H2S (R431.1); landfill gas - 150 ppm as H2S (R431.1
CO2 was estimated from the amount of carbon in the fuel and the amount of CO emitted (see Appendix C).
PM includes both PM10 and PM2.5. PM10 includes PM2.5.

Table 4-11 shows the year 2005 baseline emission inventory for biogas engines and the year 2012 remaining emission inventory, i.e., the year of full compliance with PAR 1110.2 for the various compliance options – add-on control equipment or the use of ICE replacement technology such as gas turbines, microturbines, LNG plants or a mixture of LNG plants and turbines or microturbines (assumed gas turbine or microturbines at digester facilities because of possible facility size restrictions and LNG plants at landfill gas facilities).

Table 4-11
Year 2012 Remaining Emissions for Various Biogas Facility Control Options

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM, lb/day
Year 2005 Baseline	1,859	9,555	882	464	136
ICEs with SCR and Ox Cat or other	472	8,092	555	464	136
Replace with Gas Turbines	1,148	1,900	66	464	314
Replace with Microturbines	164	642	164	464	51
Replace with LNG Plants	110	15	13	101	34
Replace LFG w LNG, DG w Turbines	513	784	32	136	142
Replace LFG w LNG, DG w Microturbines	109	269	72	136	34

- Combustion PM emissions were developed from PM10 emission factors. However, combustion PM emissions are comprised mostly of PM2.5 emissions (PM 10 emissions 98 to 99 percent PM2.5). PM includes both PM10 and PM2.5. PM10 includes PM2.5. LFG is landfill gas. LNG is liquefied natural gas.
- The values in this table are for six possible compliance options. Each compliance option is assumed to be independent so the values are not additive between compliance options.

Table 4-12 shows the year 2012 emission reductions from the year 2005 baseline for the various control options. Although control options other than installing control equipment on existing biogas ICEs may have greater emission reduction benefits, the SCAQMD is not taking credit for emission reductions from alternative control options.

Table 4-12
Estimated Criteria Emissions/Reductions in 2012 from Year 2005 Baseline for Biogas Facility Control Options

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM, lb/day
ICEs with SCR and Ox Cat or other	(1,387)	(1,463)	(327)	0	0
Replace with Gas Turbines	(710)	(7,655)	(816)	0	179
Replace with Microturbines	(1,695)	(8,913)	(718)	0	(85)
Replace with LNG Plants	(1,748)	(9,540)	(869)	(363)	(102)
Replace LFG w LNG, DG w Turbines	(1,346)	(8,771)	(850)	(328)	6.0
Replace LFG w LNG, DG w Microturbines	(1,749)	(9,286)	(810)	(328)	(102)

- Combustion PM emissions were developed from PM10 emission factors. However, combustion PM emissions are comprised mostly of PM2.5 emissions (PM 10 emissions 98 to 99 percent PM2.5). Numbers in parentheses represent emission reductions. PM includes both PM10 and PM2.5. PM10 includes PM2.5. LFG is landfill gas. LNG is liquefied natural gas.
- The values in this table are for six possible compliance options. Each compliance option is assumed to be independent so the values are not additive between compliance options.

<u>Secondary Air Quality Impacts – Operation</u>

To reduce emissions from affected ICEs, it is expected that facility operators would install appropriate air pollution control equipment. Alternatively, operators could replace ICEs with alternative technologies. The following sections evaluate potential secondary adverse air quality impacts from the operation of control equipment, emergency backup power systems that may need to be installed, or alternative ICE replacement technologies. The analysis of secondary adverse impacts is completed for CEQA purposes, using conservative assumptions. Facility operators may not choose compliance options as conservative as presented in this analysis.

<u>Secondary Air Quality Impacts – Power Plants</u>

Facility operators who replace non-biogas ICEs with electric motors and facility operators who replace biogas ICEs with alternative technologies may need additional electricity from the electricity grid than would otherwise be the case if they installed air pollution control equipment on existing affected ICEs. For example, additional electricity may be necessary for biogas ICE alternative technologies because gas turbines and microturbines are less efficient than ICEs. Facility operators who replace biogas ICEs with biogas-to-LNG plants would also need additional electricity to run the plants. Staff assumed that the electricity supplied to the grid for this additional energy would be supplied by new natural gas power plants within the district. SCAQMD staff assumed that grid power replacing engine power or work would be produced in the following ratio: 80 percent by natural gas plants and 20 percent from renewable sources, consistent with California's Renewable Portfolio Standard Program. The average fossil plant efficiency was assumed to be 36 percent based on the USEPA Acid Rain data. Emissions from power plants were derived from those in the SCAQMD annual emission reporting program. NOx and SOx emissions were not included because these emissions are capped by the SCAQMD's RECLAIM (REgional CLean Air Incentives Market) program. Tables 4-13 and 4-14 show estimated emissions from power plants supplying affected non-biogas and biogas facilities, respectively, with additional electricity. The non-biogas facility values assume facility operators would elect to replace 169 engines with electric motors as a less costly compliance option (see Appendix C).

Table 4-13
Secondary Emission Increases from Power Plants Supplying Affected Non-Biogas Facilities with Additional Electricity

Description	CO, lb/day	VOC, lb/day	PM, lb/day
2009 requirements	12.2	1.0	1.3
2010 requirements	80.2	6.5	8.4
2011 requirements	126	10.2	26.4

- Combustion emissions were developed from PM10 emission factors. However, combustion PM emissions are comprised mostly of PM2.5 emissions (98 to 99 percent PM2.5). PM includes both PM10 and PM2.5. PM10 includes PM2.5.
- CO2 and VOC emissions were based on CARB emission factors for modern central station power plants (CO = 0.1 lb/MW-hr and VOC = 0.02 lb/MW-hr.
- NOx and SOx emissions are assumed to be capped by RECLAIM.

Table 4-14
Secondary Emission Increases in 2012[a] from Power Plants Supplying Affected Biogas Facilities with Additional Electricity[b]

Description	CO, lb/day	VOC, lb/day	PM,[c] lb/day
ICEs with SCR	1.3	0.10	0.13
Replace with Gas Turbines	51	4.1	5.3
Replace with Microturbines	83	6.7	8.6
Replace LFG w LNG, DG w Turbines	292	24	31
Replace LFG w LNG, DG w Microturbines	305	25	32

a) SCAQMD staff assumed that operational emission from PAR 1110.2 concentration requirements at biogas facilities would begin in 2012.
b) NOx and SOx emissions are capped by the RELCLAIM program; therefore, it was assumed that there would be no change in NOx or SOx emissions. LFG is landfill gas. DG is digester gas.
c) Combustion emissions were developed from PM10 emission factors. However, combustion PM emissions are comprised mostly of PM2.5 emissions (98 to 99 percent PM2.5). PM includes both PM10 and PM2.5. PM10 includes PM2.5.
d) The values in this table are for six possible compliance options. Each compliance option is assumed to be independent so the values are not additive between compliance options.

Table 4-15 shows total secondary power plant emission increases in the year 2012 that would be generated to supply the electricity needs for both non-biogas ICE replacement electric motors and all possible biogas compliance options.

Table 4-15
Total Secondary Emission Increases in 2012[a] from Power Plants Supplying Affected Biogas and Non-Biogas Facilities with Additional Electricity[b]

Description	CO, lb/day	VOC, lb/day	PM,[c] lb/day
ICEs with SCR	127	10.3	26.5
Replace with Gas Turbines	177	14.2	31.6
Replace with Microturbines	209	16.8	35.0
Replace LFG w LNG, DG w Turbines	418	33.7	56.9
Replace LFG w LNG, DG w Microturbines	431	34.8	58.3

a) SCAQMD staff assumed that operational emission from PAR 1110.2 concentration requirements at biogas facilities would begin in 2012.
b) NOx and SOx emissions are capped by the RELCLAIM program; therefore, it was assumed that there would be no change in NOx or SOx emissions. LFG is landfill gas. DG is digester gas.
c) Combustion emissions were developed from PM10 emission factors. However, combustion PM emissions are comprised mostly of PM2.5 emissions (98 to 99 percent PM2.5). PM includes both PM10 and PM2.5. PM10 includes PM2.5.
d) The values in this table are for six possible compliance options. Each compliance option is assumed to be independent so the values are not additive between compliance options.

Secondary Air Quality Impacts – Ammonia Slip Emissions

Facility operators may install SCR or NOxTech control systems. Both systems use either urea or aqueous ammonia to control NOx emissions. The amount of ammonia introduced into the SCR system is approximately a one-to-one molar ratio of ammonia to NOx for optimum control efficiency, though the ratio may vary based on equipment-specific NOx reduction requirements. To ensure maximum reduction of NOx emissions, slightly more than a one-to-one molar ratio of ammonia to NOx may be injected into the exhaust, resulting in unreacted ammonia which escapes or “slips” from the stack and is commonly referred to as ‘ammonia slip.’

Under normal operating and permitted conditions, ammonia slip is approximately five to 10 ppm. Staff estimates approximately 0.44 pounds of ammonia per pound of NOx reduced would be required to reduce NOx and that 40 percent of the excess ammonia would be injected to produce a slip 10 ppm. Approximately 3,775 pounds of 19 percent ammonia or 1,266 pounds of urea would be used per day to control NOx emissions. Based on this emission factor 205 pounds of ammonia would be emitted as slip per day.

There is a potential for a slight increase in the secondary formation of particulate emissions resulting from the use of ammonia in the SCR in the presence of sulfur compounds which are present in small quantities in natural gas. While most of the fuel sulfur is converted to SO2, about 1.5 percent is converted to SO3 in the presence of the SCR catalyst. SO3 reacts with ammonia in the presence of water from the exhaust and forms ammonium sulfate and ammonia bisulfate, which is a very fine solid. Public Utility Commission-grade low sulfur natural gas contains no more than 0.75 grains/100 standard cubic feet of gas. This is roughly equivalent to 10 parts per million (ppm). Since only a fraction of the sulfur will contribute to formation of particulate, insignificant quantities of particulate will form as a result of the installation of the SCR system.

Secondary Air Quality Impacts – Emergency Backup Engines

For some types of operations, operators replacing existing natural gas engines with electric motors would also need to install emergency backup engines to provide power for necessary operations during power failures. Public comments were received on the NOP/IS and Preliminary Staff Report stating that the costs for air pollution control and monitoring equipment would cause affected facility operators to replace some existing natural gas engines with electric motors and purchase diesel emergency engines. Subsequent to the release of the NOP/IS and Preliminary Staff Report, exceptions added to PAR 1110.2 for the use of two-stroke engines, low usage engines, engines less than 500 bhp and CEMS sharing have eliminated the need for monitoring and control technology on some engines of concern to commenters. Consequently, the costs of installing control equipment, monitoring equipment, etc., on two-stroke engines, low usage engines, engines less than 500 bhp, etc., are not expected to result in operators replacing these engines with electric motors. The following two subsections analyze potential adverse secondary emissions from operating emergency back-up engines at both non-biogas and biogas facilities, respectively.

Non-Biogas Facilities

Based on a cost analysis (see Appendix C), SCAQMD staff identified operators of 225 non-biogas engines who would incur lower compliance costs by replacing their existing ICEs with electric motors instead of incurring the costs of installing emissions control and monitoring equipment, I&M, that would be required by PAR 1110.2. Not all operators with non-biogas engines in these engine categories would replace existing ICEs with electric motors based solely on lower compliance costs over ten years. Therefore, SCAQMD staff assumed that operators of 75 percent of non-biogas engines (169 engines) in the specified engine categories (see Table 4-8) would choose the alternative compliance option of replacing existing ICEs with electric motors as the most cost-effective compliance option. It is assumed that: operators of 40 percent of these engines would use the existing engines as emergency generators; operators of 20 percent of these engines would use diesel-fueled emergency engines; and operators of the remaining 40 percent of are not assumed to need an emergency engine.

The analysis further assumed that diesel emergency backup engines would operate 50 hours per year for engine testing (the maximum testing allowed per year pursuant to Rule 1470). For this analysis, it was assumed that the brake horsepower rating of the emergency backup engines installed would be equivalent to the brake horsepower rating of the existing natural gas engine replaced divided by 0.97 to account for electric motor efficiency. Diesel emission factors from 40CFR, Part 89 - Control of Emissions from New and In-Use Compression-Ignition Engines were used.

Finally, it was assumed that the emission factors for the existing natural gas engines would be the same emission factors when they are used as emergency backup. Criteria emissions from emergency engines at non-biogas facilities are presented in Tables 4-16 through 4-18.

Table 4-16
Criteria Emissions from Diesel Emergency Backup Engines at Non-Biogas Facilities

Year	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5, lb/day
2009	10.2	6.8	1.14	0.014	0.39	0.39
2010	120	78.8	13.3	0.16	4.5	4.5
2011	159	118	16.9	0.24	6.6	6.6

Table 4-17
Criteria Emissions from Natural Gas Emergency Backup Engines at Non-Biogas Facilities

Year	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5, lb/day
2009	11.3	5.8	2.1	0.039	0.27	0.27
2010	55.2	134.1	28.9	0.50	3.4	3.4
2011	68.7	262	31.0	0.61	4.2	4.2

Table 4-18
Total Criteria Emissions from Emergency Backup Engines at Non-Biogas Facilities

Year	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5, lb/day
2009	21.6	12.6	3.2	0.053	0.65	0.65
2010	175	213	42.3	0.67	8.0	8.0
2011	228	379	47.9	0.85	10.8	10.8

Includes emission from both biogas and non-biogas emergency engines.

Biogas Facilities

Operators of biogas facilities who replace existing ICEs with an alternate technology may also require emergency backup ICEs to run compressors and pumps in the event of a power outage. It was assumed that landfill gas facilities would not need to run during emergency loss of power from the electrical grid, since it is believed that landfill gas facilities flare landfill gas during power loss. Digester gas facilities may need to continue to run if power is lost from the electrical grid, since digester gas facilities would need to continually operate pumps. Based on these assumptions and the survey information, it is likely that 33 digester gas facilities may need diesel emergency generators. It was assumed that operators of 80 percent (26 facilities) of the digester gas facilities that need emergency backup engines would use their existing natural gas engines for emergency backup power. Operators of the remaining 20 percent (seven facilities) were assumed to use diesel emergency generators.

The same assumptions used for non-biogas emergency engines were used to develop emissions for digester emergency generators. It was assumed that the diesel emergency engines would be sized for the increased grid dependency (power produced by ICE less power produced by alternative technology or power required to compensate for the pressure drop of add-on control). For the case of blowers replaced by alternative technology, it was assumed that the emergency generator would be sized to replace the shaft work produced by the ICEs. Emergency engines were assumed to operate 50 hours per year. Diesel emission factors from 40CFR, Part 89 - Control of Emissions from New and In-Use Compression-Ignition Engines were used. If existing engines are used as emergency generators for ICE alternative technology, then it was assumed that the emergency generator emissions would be the same as the existing engines. .

Facility operators who install add-on control technology to existing ICEs are not expected to need new emergency backup engines to comply with PAR 1110.2. It is expected that operators would use existing emergency engines or continue to operator without emergency power. If these operators were to install emergency engines, it would be for reasons other than complying with PAR 1110.2.

Based on the above assumptions, criteria emissions from diesel fueled emergency backup engines at biogas facilities are presented in Tables 4-19 through 4-21. Table 4-19 shows emissions from emergency diesel backup engines, Table 4-20 shows emissions from natural gas-fueled emergency backup engines, and Table 4-21 shows total emissions from both diesel fueled- and natural gas-fueled emergency backup engines.

Table 4-19
Criteria Emissions from Diesel-Fueled
Emergency Backup Engines at Biogas Facilities in 2012

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5, lb/day
Replace with Gas Turbines	9.4	7.5	0.96	0.01	0.42	0.41
Replace with Microturbines	22.6	15.7	2.46	0.02	0.89	0.87
Replace LFG w LNG, DG w Turbines	9.4	7.5	0.96	0.01	0.42	0.41
Replace LFG w LNG, DG w Microturbines	22.6	15.7	2.46	0.02	0.89	0.87

- PM10 includes PM2.5. LFG is landfill gas. DG is digester gas. LNG is liquefied natural gas.
- The values in this table are for six possible compliance options. Each compliance option is assumed to be independent so the values are not additive between compliance options.

Table 4-20
Criteria Emissions from Natural Gas-Fueled
Emergency Backup Engines at Biogas Facilities in 2012

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5, lb/day
Replace with Gas Turbines	14.5	70.4	6.4	0.28	1.9	1.9
Replace with Microturbines	20.6	99.6	9.1	0.40	2.8	2.7
Replace LFG w LNG, DG w Turbines	14.5	70.4	6.4	0.28	1.9	1.9
Replace LFG w LNG, DG w Microturbines	20.6	99.6	9.1	0.40	2.8	2.7

PM10 includes PM2.5. LFG is landfill gas. DG is digester gas. LNG is liquefied natural gas.

Table 4-21
Total Criteria Emissions from Diesel-fueled and Natural Gas-fueled Emergency Engines at Biogas Facilities in 2012

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5, lb/day
Replace with Gas Turbines	24.0	78.0	7.4	0.30	2.4	2.3
Replace with Microturbines	43.2	115.3	11.5	0.42	3.6	3.6
Replace LFG w LNG, DG w Turbines	23.3	77.4	7.3	0.30	2.3	2.3
Replace LFG w LNG, DG w Microturbines	42.2	114.4	11.5	0.42	3.6	3.6

- PM10 includes PM2.5. LFG is landfill gas. DG is digester gas. LNG is liquefied natural gas.
- The values in this table are for six possible compliance options. Each compliance option is assumed to be independent so the values are not additive between compliance options.

Secondary Air Quality Impacts – Spent Catalyst Disposal Trips

Over time, the effectiveness of catalysts used in both SCR and oxidation air pollution control equipment lose their effectiveness primarily due to clogging of the catalyst pores. Because oxidation catalysts use metals that have substantial economic value, depending on the size of the control unit, they may be recycled and reused. Ceramic-based SCR catalysts can be crushed and reused in concrete. Metal-based SCR catalysts and some ceramic-based catalysts, if not recycled, would be crushed, encased in concrete and eventually disposed of in a Class II landfill or a Class III landfill that is fitted with liners. A detailed discussion on the disposal of spent catalysis can be found in the Solid/Hazardous Waste Impact Section below. While there are several Class II and Class III landfills in the district, there are only three Class I facilities in California, which are located outside of the district. The three Class I facilities are Chemical Waste Management Kettleman Hills in Kettleman City, CA; Clean Harbors Buttonwillow in Buttonwillow, CA and Clean Harbors Westmorland in Westemorland, CA. Since Class I facilities are further away, and therefore require more travel, as a worst-case, it is assumed that all catalyst waste is disposed of at one of the Class I facilities.

As a worst-case analysis, SCAQMD staff assumed that catalyst would be changed out every three years. Because biogas facility operators are not expected to install add-on controls or replace ICEs with alternative technology until after the technology assessment in 2010, SCAQMD staff does not expect the maximum number of new and replacement catalysts trips to begin until 2014. Based on the SCAQMD engine survey operators of approximately 28 biogas facilities could potentially install SCR and oxidation catalyst systems and operators of seven non-biogas facilities would need to install oxidation catalyst. Based on the size of the largest SCR and oxidation catalysts, it is expected that three truck trips would be necessary to dispose of the catalysts from the largest affected facilities. None of the operators at the 45 facilities with existing catalysts who would need to upgrade their catalysts to comply with PAR 1110.2 would require more than one truck trip for the entire catalyst bed replacement. Since the facilities that require upgrades already dispose of catalysts, there is no expected change in disposal truck trips (i.e., no additional truck trips). Given that catalysts will be installed at different times and are subject to different operating parameters, it is unlikely that spent catalysts would all be replaced on the same day. As a result, it was conservatively assumed that there would be up to two large spent catalyst units disposed of on a single day. Therefore, a maximum of six additional truck trips would occur on any one day as a result of implementing PAR 1110.2 (three trucks per facility from two facilities). There are three possible Class I disposal sites in California: Kettleman City (178 miles from Los Angeles), Buttonwillow (133 miles from Los Angeles), and Westmorland (192 miles from Los Angeles). The intermediate distance, 178 miles per one-way trip, was chosen for this analysis. Spent catalyst haul truck emissions are shown in the first line of Tables 4-22 through 4-26.

Note that Tables 4-22 through 4-26 also show other types of secondary air quality impacts from various types of truck trips based on different compliance options for biogas engines. The information shown in Tables 4-22 through 4-26 assumes that operators 169 non-biogas engines would replace their engines with electric motors (see Table 4-8) and that operators of all remaining non-biogas engines not exempted by the low-use exemption, a total of 264 engines, would comply with PAR 1110.2. Analysis details for the information presented in Tables 4-22 through 4-26 can be found in Appendix C.

Table 4-22
2014 Secondary Operational Criteria Emission Impacts from Delivery and Disposal Trips – Non-Biogas and Biogas SCR and Oxidation Catalyst Compliance Options Only

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5, lb/day
Spent Catalyst Haul Truck	101	30.9	8.0	0.085	4.9	4.8
New Catalyst Delivery Truck	17.0	5.2	1.34	0.014	0.83	0.80
Spent Carbon Haul Truck	5.66	1.74	0.45	0.0048	0.28	0.27
New Carbon Delivery Truck	5.66	1.74	0.45	0.0048	0.28	0.27
Source Test	5.66	1.74	0.45	0.0048	0.28	0.27
Ammonia Delivery	0.00	0.00	0.00	0.0000	0.00	0.00
Diesel Delivery	5.66	1.74	0.45	0.0048	0.28	0.27
Total	140	43.0	11.1	0.12	6.9	6.6

PM10 includes PM2.5. PM2.5 emissions were estimated using the CEIDARS PM10 to PM2.5 fraction for on-road diesel trucks (96.45%).

Table 4-23
2014 Secondary Operational Criteria Emission Impacts from Delivery and Disposal Trips – Non-Biogas Oxidation Catalyst Compliance Option with Biogas Gas Turbine Compliance Option

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5, lb/day
Spent Catalyst Haul Truck	101	30.9	8.0	0.085	4.9	4.8
New Catalyst Delivery Truck	17.0	5.2	1.3	0.014	0.83	0.80
Spent Carbon Haul Truck	5.7	1.7	0.4	0.0048	0.28	0.27
New Carbon Delivery Truck	5.7	1.7	0.4	0.0048	0.28	0.27
Source Test	5.7	1.7	0.4	0.0048	0.28	0.27
Diesel Delivery	5.7	1.7	0.4	0.0048	0.28	0.27
Total	140	43.0	11.1	0.12	6.9	6.6

PM10 includes PM2.5. PM2.5 emissions were estimated using the CEIDARS PM10 to PM2.5 fraction for on-road diesel trucks (96.45%).

Table 4-24
2014 Secondary Operational Criteria Emission Impacts from Delivery and Disposal Trips – Non-Biogas Oxidation Catalyst Option with Biogas Microturbine Compliance Option

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5, lb/day
Spent Catalyst Haul Truck	101	30.9	8.0	0.085	4.93	4.8
New Catalyst Delivery Truck	17.0	5.2	1.3	0.014	0.83	0.80
Spent Carbon Haul Truck	5.7	1.7	0.45	0.0048	0.28	0.27
New Carbon Delivery Truck	5.7	1.7	0.45	0.0048	0.28	0.27
Source Test	5.7	1.7	0.45	0.0048	0.28	0.27
Diesel Delivery	5.7	1.7	0.45	0.0048	0.28	0.27
Total	140	43.0	11.1	0.12	6.9	6.6

PM10 includes PM2.5. PM2.5 emissions were estimated using the CEIDARS PM10 to PM2.5 fraction for on-road diesel trucks (96.45%).

Table 4-25
Secondary Operational Criteria Emission Impacts from Delivery and Disposal Trips – Non-Biogas Oxidation Catalyst Option with Biogas Gas Turbine at Digester Facilities and LNG Plants for Landfill Gas Facility Compliance Options

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5, lb/day
Spent Catalyst Haul Truck	101	30.9	7.97	0.085	4.93	4.8
New Catalyst Delivery Truck	17.0	5.2	1.34	0.014	0.83	0.80
Spent Carbon Haul Truck	5.7	1.7	0.45	0.0048	0.28	0.27
New Carbon Delivery Truck	5.7	1.7	0.45	0.0048	0.28	0.27
Source Test	5.7	1.7	0.448	0.0048	0.28	0.27
Diesel Delivery	5.7	1.7	0.448	0.0048	0.28	0.27
LNG Haul Truck	125	38.2	9.8	0.105	6.10	5.9
Total	265	81.2	20.9	0.22	13.0	12.5

PM10 includes PM2.5. PM2.5 emissions were estimated using the CEIDARS PM10 to PM2.5 fraction for on-road diesel trucks (96.45%).

Table 4-26
Secondary Operational Criteria Emission Impacts from Delivery and Disposal Trips – Non-Biogas Oxidation Catalyst Option with Non-Biogas and Microturbine at Digester Facilities and LNG Plants for Landfill Gas Facility Compliance Options

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5, lb/day
Spent Catalyst Haul Truck	101	30.9	8.0	0.0846	4.9	4.8
New Catalyst Delivery Truck	17.0	5.21	1.34	0.0143	0.83	0.80
Spent Carbon Haul Truck	5.7	1.74	0.45	0.0048	0.28	0.27
New Carbon Delivery Truck	5.7	1.74	0.45	0.0048	0.28	0.27
Source Test	5.7	1.74	0.45	0.0048	0.28	0.27
Diesel Delivery	5.7	1.74	0.45	0.0048	0.28	0.27
LNG Haul Truck	125	38.2	9.8	0.105	6.1	5.88
Total	265	81.2	20.9	0.22	13.0	12.5

PM10 includes PM2.5. PM2.5 emissions were estimated using the CEIDARS PM10 to PM2.5 fraction for on-road diesel trucks (96.45%).

Secondary Air Quality Impacts – Spent Activated Carbon Disposal Trips

Activated carbon is typically used in pre-treatment systems for biogas facilities where influent streams have high sulfur content that could potential foul or plug control technology. Digester gas may have high siloxane, hydrogen sulfide (H2S) and VOC content, that if not removed may contaminate catalysis. Landfill facilities may not require pretreatment systems.

Based on survey responses there are approximately 28 biogas facilities. Of the 28 facilities, there are approximately 12 landfill facilities in the district, approximately 15 digester gas facilities, one facility that handles both landfill and digester gas. Based on discussions with a contractor, it is believed that activated carbon used in pre-treatment systems would be replaced every three months. However, even though all 28 biogas facilities are expected to need pre-treatment systems, SCAQMD staff assumed that catalyst would be replaced at two facilities on any one day. Based upon available information, SCAQMD staff estimated that two truck trips would be required per facility. One trip to collect and dispose of spent activated catalyst and a second trip to deliver new catalyst. Activated carbon is typically regenerated and reused in treatment systems. Eventually spent activated carbon residues in the form of ash are disposed of in local landfills. Because affected facilities are located throughout the district and the locations of the carbon suppliers and landfill where spent carbon residues would be disposed of are unknown, the analysis assumed a haul trip distance of 30 miles per one-way trip.

Secondary operational criteria emissions from truck trips to supply activated carbon and dispose of carbon residues are presented in Tables 4-22 through 4-26. Detailed calculations are presented in Appendix C.

Secondary Air Quality Impacts – Ammonia/Urea Delivery Trips

Ammonia use would be required for facilities where operators install either SCR or NSCR systems, primarily to control NOx emissions. The number of delivery trips was estimated from the amount of ammonia that would be required to reduce NOx concentrations to the PAR 1110.2 limit of 11 ppm of NOx. To reduce hazard impact (see Hazards/Hazardous Material below), SCAQMD policy prohibits the use of new anhydrous ammonia control systems for air pollution control, restricting ammonia for new control systems to 19 percent aqueous ammonia. Therefore, based on SCAQMD policy regarding ammonia used in air pollution control systems, existing engine horsepower, and the assumption that operators of 28 biogas facilities, SCAQMD staff conservatively assumed that up to 38 ammonia deliver truck trips could occur per year, no more than one ammonia delivery truck trip would occur on any single day. Because the actual ammonia supplier for each facility is unknown, staff assumed the trip length for ammonia delivery truck trips were 30 miles per one-way trip.

Secondary operational criteria emissions from ammonia delivery truck trips are presented in Table 4-22. The analysis assumes that alternative biogas compliance options would not require ammonia to comply with PAR 1110.2 NOx emission concentrations because these compliance options would no longer be subject to PAR 1110.2 requirements. Detailed calculations are presented in Appendix C.

Secondary Air Quality Impacts – LNG Delivery Trips

Operators at biogas facilities who choose the compliance option of replacing existing ICEs with LNG plants could use the LNG onsite as a combustion fuel or export it offsite for use as a vehicle fuel, for example. LNG produced at biogas facilities would most likely be exported offsite using cryogenic tanker trucks. The LNG plant at the Bowerman Landfill in Orange County was used as a model for evaluating secondary air quality impacts from LNG truck deliveries. Based on the quality and amount of natural gas generated at the Bowerman Landfill, operators are expected to use 10,000-gallon cryogenic tanker trucks to export LNG, with one LNG truck delivery trip occurring every other day. Assuming a similar quality of landfill gas will be generated at affected biogas facilities as is generated at the Bowerman Landfill and assuming the use of 10,000-gallon cryogenic tanker trucks, it is expected that approximately 33 LNG delivery truck trips would occur on any single day if operators of all 22 biogas facilities install LNG plants. The estimate of 22 biogas facilities is conservative since only 12 of the biogas facilities are landfill gas facilities. Because the actual LNG customer for each facility is unknown, staff assumed the trip length for LNG delivery truck trips were 40 miles per one-way trip.

Secondary operational criteria emissions from operating travel activities are presented in Tables 4-22 and 4-26. Detailed calculations are presented in Appendix B.

Total Operational Criteria Emissions from PAR 1110.2

Tables 4-27 through 4-31 show the year 2005 baseline inventory for all existing equipment and the remaining emission inventory for the compliance years shown, based on emission reductions anticipated for each compliance year. The information shown in Tables 4-27 through 4-31 assumes that operators of 169 non-biogas engines would replace their engines with electric motors (see Table 4-8) and that operators of all remaining non-biogas engines, a total of 624 engines would comply with PAR 1110.2. Table 4-27 shows the remaining emissions by compliance year for the compliance option of all biogas plant operators retrofitting using SCR. Table 4-28 shows the remaining emissions by compliance year for the compliance option of all biogas plant operators replacing ICEs with gas turbines. Table 4-29 shows the remaining emissions by compliance year for the compliance option of biogas operators replacing ICEs with microturbines. Table 4-30 shows the remaining emissions by compliance year for the compliance option of biogas operators replacing ICEs with digester plant and LNG plants at landfills. Table 4-31 shows the remaining emissions by compliance year for the compliance option of operators replacing ICEs with microturbines and landfill gas facility operators replacing ICEs with LNG plants. Tables take into account all secondary adverse operational air quality impacts described in the above subsections. Finally, the remaining inventory for the year 2014 for each of the scenarios shown in Tables 4-27 through 4-31 because this is the first year that SCR catalysts are expected to be replaced, based on a three-year operating life.

Table 4-27
Total Criteria Emissions from Operation with Non-biogas Facilities and SCR at All Biogas Facilities

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5 lb/day
2005 Baseline	9,195	54,243	2,493	551	877	875
2008	~~8,999~~ 9,004	~~53,867~~ 53,900	~~2,458~~ 2,467	~~544~~ 545	~~872~~ 873	~~870~~ 871
2009	~~6,410~~ 6,415	~~22,399~~ 22,432	~~1,790~~ 1,799	~~543~~ 544	~~858~~ 859	~~856~~ 857
2010	~~5,823~~ 5,828	~~17,295~~ 17,328	~~1,281~~ 1,290	~~534~~ 535	~~837~~ 838	~~835~~ 836
2011	~~5,345~~ 5,350	~~13,475~~ 13,508	~~1,207~~ 1,216	~~528~~ 529	~~821~~ 822	~~819~~ 820
2012	4,125	13,423	1,011	538	830	829
2014	4,184	13,441	1,015	538	833	831

PM10 includes PM2.5. PM2.5 emissions were estimated using the CEIDARS PM10 to PM2.5 fraction by combustion source and fuel type.

Table 4-28
Total Criteria Emissions from Operation with Non-biogas Facilities and Gas Turbines at All Biogas Facilities

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5 lb/day
2005 Baseline	9,195	54,243	2,493	551	877	875
2008	~~8,999~~ 9,004	~~53,867~~ 53,900	~~2,458~~ 2,467	~~544~~ 545	~~872~~ 873	~~870~~ 871
2009	~~6,410~~ 6,415	~~22,399~~ 22,432	~~1,790~~ 1,799	~~543~~ 544	~~858~~ 859	~~856~~ 857
2010	~~5,823~~ 5,828	~~17,295~~ 17,328	~~1,281~~ 1,290	~~534~~ 535	~~837~~ 838	~~835~~ 836
2011	~~5,339~~ 5,344	~~13,473~~ 13,506	~~1,206~~ 1,215	~~528~~ 529	~~821~~ 822	~~819~~ 820
2012	4,825	7,357	533	538	1,016	1,014
2014	4,884	7,375	537	538	1,019	1,017

PM10 includes PM2.5. PM2.5 emissions were estimated using the CEIDARS PM10 to PM2.5 fraction by combustion source and fuel type.

Table 4-29
Total Criteria Emissions from Operation with Non-biogas Facilities and Microturbines at All Biogas Facilities

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5 lb/day
2005 Baseline	9,195	54,243	2,493	551	877	875
2008	~~8,999~~ 9,004	~~53,867~~ 53,900	~~2,458~~ 2,467	~~544~~ 545	~~872~~ 873	~~870~~ 871
2009	~~6,410~~ 6,415	~~22,399~~ 22,432	~~1,790~~ 1,799	~~543~~ 544	~~858~~ 859	~~856~~ 857
2010	~~5,823~~ 5,828	~~17,295~~ 17,328	~~1,281~~ 1,290	~~534~~ 535	~~837~~ 838	~~835~~ 836
2011	~~5,339~~ 5,344	~~13,473~~ 13,506	~~1,206~~ 1,215	~~528~~ 529	~~821~~ 822	~~819~~ 820
2012	3,860	6,169	638	538	757	756
2014	3,919	6,187	643	538	760	758

Table 4-30
Total Criteria Emissions from Operation with Non-biogas Facilities and Gas Turbines at Digester Gas Plants and LNG Facilities at Landfill Gas Plants

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5 lb/day
2005 Baseline	9,195	54,243	2,493	551	877	875
2008	~~8,999~~ 9,004	~~53,867~~ 53,900	~~2,458~~ 2,467	~~544~~ 545	~~872~~ 873	~~870~~ 871
2009	~~6,440~~ 6,445	~~23,215~~ 23,248	~~1,814~~ 1,823	~~543~~ 544	~~860~~ 861	~~858~~ 859
2010	~~5,823~~ 5,828	~~17,295~~ 17,328	~~1,281~~ 1,290	~~534~~ 535	~~837~~ 838	~~835~~ 836
2011	~~5,390~~ 5,395	~~13,489~~ 13,522	~~1,210~~ 1,219	~~528~~ 529	~~823~~ 824	~~821~~ 822
2012	4,254	6,503	523	211	872	870
2014	4,373	6,540	533	211	878	876

PM10 includes PM2.5. PM2.5 emissions were estimated using the CEIDARS PM10 to PM2.5 fraction by combustion source and fuel type.

Table 4-31
Total Criteria Emissions from Operation with Non-biogas Facilities and Microturbines at Digester Gas Plants and LNG Facilities at Landfill Gas Plants

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5 lb/day
2005 Baseline	9,195	54,243	2,493	551	877	875
2008	~~8,999~~ 9,004	~~53,867~~ 53,900	~~2,458~~ 2,467	~~544~~ 545	~~872~~ 873	~~870~~ 871
2009	~~6,410~~ 6,415	~~22,399~~ 22,432	~~1,790~~ 1,799	~~543~~ 544	~~858~~ 859	~~856~~ 857
2010	~~5,823~~ 5,828	~~17,295~~ 17,328	~~1,281~~ 1,290	~~534~~ 535	~~837~~ 838	~~835~~ 836
2011	~~5,390~~ 5,395	~~13,489~~ 13,522	~~1,210~~ 1,219	~~528~~ 529	~~823~~ 824	~~821~~ 822
2012	3,870	6,038	569	211	767	765
2014	3,989	6,075	578	211	773	771

PM10 includes PM2.5. PM2.5 emissions were estimated using the CEIDARS PM10 to PM2.5 fraction by combustion source and fuel type.

Construction Air Quality Impacts

Installing control and monitoring equipment to comply with PAR 1110.2 emission concentrations and monitoring provisions or replacing existing ICEs with alternative technologies is expected to require construction activities. The following subsections analyze construction air quality impacts anticipated from implementing PAR 1110.2.

Construction Criteria Emissions

Based on a survey of facilities with gaseous- and liquid-fueled engines, SCAQMD staff estimates that 242 engines would become subject to source tests starting in 2007; 240 facilities would require minor construction to install infrastructure (sampling ports, platforms, safe access and utilities) by September 2008; 16 facilities are expected to need air/fuel ratio controllers installed in 2009; 20 facilities would need installation of CO analyzers; 24 NOx-CO CEMS are expected to be installed by July 2011; seven facilities would need oxidation catalyst by July 2011; 45 facilities would need modification to enhance three-way catalyst by July 2011; and 28 facilities would need SCR by July 2012. Table 4-32 presents the number of facilities requiring some type of construction activity and the compliances dates when construction must be completed.

Table 4-32
Number of Facilities Where Construction Activities Are Expected to Occur

Project - Facilities	2008	2009	2010	2011	2012	Total
Increased Source Testing	242					242
Inspection & Monitoring	242					242
Install Sampling Infrastructure	240					240
Install AFRC		16				16
Upgrade Three-Way Catalyst			15	30		45
Install Oxidation Catalyst			5	2		7
Install CEMS		4	10	10		24
Install CO Analyzer			15	5		20
Install Pretreatment, SCR, Ox Cat or ICE Alternative Technology					28	28
Facilities with Electrified Engines		4	13	88		105

Construction to install new or modify existing control technologies; replace engines with electric motors; or install infrastructure may require cranes, loaders, forklifts, welders and generator sets. Installation of controllers, analyzers, and CEMS systems are likely to require less heavy equipment. All construction would require delivery truck and worker trips. Table 4-33 presents expected construction equipment expected to be required for the various compliance options.

Construction emission calculations are based on the expected number of facilities expected to be affected and the construction schedule (Table 4-33). Tables 4-34 and 35 show total peak daily construction emissions for each year up to the final compliance date for the various compliance options. The peak daily construction emissions shown in Tables 4-34 and 4-35 assume that operators 169 non-biogas engines would replace their engines with electric motors (see Table 4-8) and that operators of all remaining non-biogas engines, a total of 624 engines, would comply with PAR 1110.2. Table 4-34 shows the construction emissions for biogas and non-biogas facilities by compliance year for the compliance option of all biogas plant operators retrofitting their equipment with SCR, replacing ICEs with gas turbines or replacing ICEs with microturbines. Table 4-38 shows the remaining emissions for biogas and non-biogas facilities by compliance year for the compliance option of digester operators replacing ICEs with gas turbines or microturbines and landfill gas facility operators replacing ICEs with LNG plants. Details of the construction analysis can be found in Appendix C.

Table 4-33
Construction Equipment by Technology Installed or Replaced

Compliance Option/Equipment	Construction Equipment Type	No. of Construction Equipment	Operation Time hour/day
ICE engine removal, three-way catalyst, SCR, NOxTech, CL.AIR®, gas turbine, boiler, microturbines, fuel cell, emergency diesel ICE - Paving	Pavers	1	4
	Paving Equipment	1	4
	Rollers	1	2
	Cement and Mortar Mixers	1	3
	Tractors/Loaders/Backhoes	1	4
ICE engine removal, three-way catalyst, SCR, NOxTech, CL.AIR®, gas turbine, boiler, microturbines, fuel cell, emergency diesel ICE - Construction	Cranes	1	7
	Rubber Tired Loaders	2	7
	Forklifts	3	7
	Welder	1	7
	Generator Sets	1	7
Source Testing Infrastructure, CEMS	Cranes	1	4
	Rubber Tired Loaders	1	4
	Forklifts	1	4
	Welder	1	7
	Generator Sets	1	7
CO Analyzer, ATRC	Forklifts/Electric Lift	1	4
LNG Plant - Grading	Scrapers	1	8
	Graders	1	8
	Tractors/Loaders/Backhoes	1	7
LNG Plant - Paving	Pavers	1	8
	Paving Equipment	1	8
	Rollers	2	8
	Cement and Mortar Mixers	1	3
	Tractors/Loaders/Backhoes	1	8
LNG Plant - Construction	Cranes	2	7
	Rubber Tired Loaders	2	7
	Forklifts	2	7
	Welder	3	7
	Generator Sets	3	7

Table 4-34
Criteria Construction Emissions for Biogas and Non-biogas Facilities from Installing SCR, Gas Turbines or Microturbines at All Biogas Facilities

Description*	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5 lb/day
2008	89.8	42.1	12.0	0.08	5.0	4.6
2009	88.9	39.5	11.1	0.08	4.7	4.4
2010	141.4	61.8	17.6	0.13	7.4	6.9
2011	247	106	30.4	0.23	12.9	11.9
2012	52.5	22.3	6.4	0.05	2.7	2.5

* Peak daily construction emissions associated with meeting specified PAR 1110.2 requirements by the specified compliance dates.
PM10 includes PM2.5. PM2.5 emissions were estimated using the CEIDARS PM10 to PM2.5 fraction by combustion source and fuel type.

Table 4-35
Criteria Construction Emissions for Biogas and Non-biogas Facilities from Installing Gas Turbines or Microturbines at Digester Gas Plants and LNG Facilities at Landfill Gas Plants

Description*	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5 lb/day
2008	90	42.1	12.0	0.08	5.0	4.6
2009	88.9	39.5	11.1	0.08	4.7	4.4
2010	141.4	61.8	17.6	0.13	7.4	6.9
2011	682	291	84.1	0.60	48.4	35.6
2012	488	206.6	60.2	0.43	38.3	26.2

* Peak daily construction emissions associated with meeting specified PAR 1110.2 requirements by the specified compliance dates.
PM10 includes PM2.5. PM2.5 emissions were estimated using the CEIDARS PM10 to PM2.5 fraction by combustion source and fuel type.

As shown in Tables 4-34 and 4-35, operators of biogas facilities who choose the compliance options of replacing ICEs with alternative technologies, LNG plants in particular, would require the most construction equipment, therefore creating the highest peak daily construction emissions. However, not all biogas facilities would have enough space to install LNG plants, as these plants may require up to three acres of land. It is not likely that most digester gas facilities would have the sufficient available space to install LNG facilities. In addition, LNG facilities require the highest capital expenditures. The CEC estimates that gas turbines may be a better option than ICEs for facilities between 10 to 18 MW when all factors (e.g., economic, emissions, etc.) are taken into account.[26]

[26] CEC, Landfill Gas-To-Energy Potential in California, Staff Report, 500-02-041V1, September, 2002.

Criteria Pollutant Significance Determination

Since construction and operational activities overlap during certain years, the criteria pollutants peak daily emissions were estimated per PAR 1110.2 implementation year and 2014 which represents an average operational year. The year 2014 was chosen as an average operational year since routine catalyst replacement would begin in 2014. Since it was assumed that SCR catalysts would be replaced every three years and biogas facility operators are not expected to install add-on control or ICE replacement technology until after the technology review in 2010; therefore, routine catalyst replacement at biogas facilities would not occur until after the year 2012, starting approximately in 2014.

As noted previously, the analysis peak daily construction emissions assumes that operators of 169 non-biogas engines would replace their engines with electric motors (see Table 4-8) because this is expected to be a less costly compliance option than other compliance options. Further, the analysis assumed that operators of all remaining non-biogas engines, a total of 624 engines, would to comply with PAR 1110.2.

Tables 4-36 through 4-40 present the total net remaining emissions by compliance year that takes into consideration the declining operating emissions inventory from affected equipment reducing emissions to comply with PAR 1110.2 and increased construction emissions from installing air pollution control and monitoring equipment or installing alternative compliance technologies. The tables take into account all secondary adverse operational air quality impacts described in the above subsections. Table 4-36 shows the remaining emissions by compliance year and construction emissions for the compliance option of all biogas plant operators retrofitting using SCR. Table 4-37 shows the remaining emissions by compliance year and construction emissions for the compliance option of all biogas plant operators replacing ICEs with gas turbines. Table 4-38 shows the remaining emissions by compliance year and construction emissions for the compliance option of biogas operators replacing ICEs with microturbines. Table 4-39 shows the remaining emissions by compliance year and construction emissions for the compliance option of biogas operators replacing ICEs with digester plant and LNG plants at landfills. Table 4-40 shows the remaining emissions by compliance year and construction emissions for the compliance option of operators replacing ICEs with microturbines and landfill gas facility operators replacing ICEs with LNG plants. Finally, the remaining inventory for the year 2014 for each of the scenarios is shown in Tables 4-36 through 4-40 because this is the first year that SCR catalysts are expected to be replaced, based on a three-year operating life.

Table 4-36
Net Remaining Criteria Emissions from Non-biogas Facilities and the SCR Compliance Option at All Biogas Facilities

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5 lb/day
2008	~~9,089~~ 9,094	~~53,909~~ 53,942	~~2,470~~ 2,479	~~544~~ 545	~~877~~ 878	~~875~~ 876
2009	~~6,410~~ 6,415	~~22,399~~ 22,432	~~1,790~~ 1,799	~~543~~ 544	~~858~~ 859	~~856~~ 857
2010	~~5,964~~ 5,969	~~17,357~~ 17,390	~~1,298~~ 1,307	~~534~~ 535	~~844~~ 845	~~842~~ 843
2011	~~5,591~~ 5,596	~~13,581~~ 13,614	~~1,237~~ 1,246	~~529~~ 530	~~834~~ 835	~~831~~ 832
2012	4,178	13,445	1,017	538	833	831
2014	4,184	13,441	1,015	538	833	831

Table includes construction and operational emissions. Construction emission included both biogas and non-biogas emissions from on-site (construction equipment, fugitive dust) and off-site travel. Operational emissions include biogas and non-biogas emissions from on-site (ICE) and offsite travel (delivery trucks).
Peak daily construction emissions associated with meeting specified PAR 1110.2 requirements by the specified compliance dates.
PM10 includes PM2.5. PM2.5 emissions were estimated using the CEIDARS PM10 to PM2.5 fraction by combustion source and fuel type.

‘

Table 4-37
Net Remaining Criteria Emissions from Non-biogas Facilities and the Gas Turbine Compliance Option at All Biogas Facilities

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5 lb/day
2008	~~9,089~~ 9,094	~~53,909~~ 53,942	~~2,470~~ 2,479	~~544~~ 545	~~877~~ 878	~~875~~ 876
2009	~~6,410~~ 6,415	~~22,399~~ 22,432	~~1,790~~ 1,799	~~543~~ 544	~~858~~ 859	~~856~~ 857
2010	~~5,964~~ 5,969	~~17,357~~ 17,390	~~1,298~~ 1,307	~~534~~ 535	~~844~~ 845	~~842~~ 843
2011	~~5,586~~ 5,591	~~13,579~~ 13,612	~~1,237~~ 1,246	~~529~~ 530	~~833~~ 834	~~831~~ 832
2012	4,878	7,380	539	538	1,019	1,017
2014	4,884	7,375	537	538	1,019	1,017

Table includes construction and operational emissions. Construction emission included both biogas and non-biogas emissions from on-site (construction equipment, fugitive dust) and off-site travel. Operational emissions include biogas and non-biogas emissions from on-site (gas turbines, emergency engines) and offsite travel (delivery trucks and power plants).
Peak daily construction emissions associated with meeting specified PAR 1110.2 requirements by the specified compliance dates.
PM10 includes PM2.5. PM2.5 emissions were estimated using the CEIDARS PM10 to PM2.5 fraction by combustion source and fuel type.

Table 4-38
Net Remaining Criteria Emissions from Non-biogas Facilities and the Microturbine Compliance Option at All Biogas Facilities

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5 lb/day
2008	~~9,089~~ 9,094	~~53,909~~ 53,942	~~2,470~~ 2,479	~~544~~ 545	~~877~~ 878	~~875~~ 876
2009	~~6,410~~ 6,415	~~22,399~~ 22,432	~~1,790~~ 1,799	~~543~~ 544	~~858~~ 859	~~856~~ 857
2010	~~5,964~~ 5,969	~~17,357~~ 17,390	~~1,298~~ 1,307	~~534~~ 535	~~844~~ 845	~~842~~ 843
2011	~~5,586~~ 5,591	~~13,579~~ 13,612	~~1,237~~ 1,246	~~529~~ 530	~~833~~ 834	~~831~~ 832
2012	3,913	6,192	644	538	760	758
2014	3,919	6,187	643	538	760	758

Table includes construction and operational emissions. Construction emission included both biogas and non-biogas emissions from on-site (construction equipment, fugitive dust) and off-site travel. Operational emissions include biogas and non-biogas emissions from on-site (microturbines, emergency engines) and offsite travel (delivery trucks and power plants).
Peak daily construction emissions associated with meeting specified PAR 1110.2 requirements by the specified compliance dates.
PM10 includes PM2.5. PM2.5 emissions were estimated using the CEIDARS PM10 to PM2.5 fraction by combustion source and fuel type.

Table 4-39
Net Remaining Criteria Emissions from Non-biogas Facilities and the Gas Turbines at Digester Gas Facilities and LNG Facilities at Landfills Compliance Option for Biogas Facilities

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5 lb/day
2008	~~9,089~~ 9,094	~~53,909~~ 53,942	~~2,470~~ 2,479	~~544~~ 545	~~877~~ 878	~~875~~ 876
2009	~~6,410~~ 6,415	~~22,399~~ 22,432	~~1,790~~ 1,799	~~543~~ 544	~~858~~ 859	~~856~~ 857
2010	~~5,964~~ 5,969	~~17,357~~ 17,390	~~1,298~~ 1,307	~~534~~ 535	~~844~~ 845	~~842~~ 843
2011	~~6,072~~ 6,077	~~13,779~~ 13,812	~~1,295~~ 1,304	~~529~~ 530	~~872~~ 873	~~857~~ 858
2012	4,742	6,710	584	211	911	896
2014	4,373	6,540	533	211	878	876

Table includes construction and operational emissions. Construction emission included both biogas and non-biogas emissions from on-site (construction equipment, fugitive dust) and off-site travel. Operational emissions include biogas and non-biogas emissions from on-site (gas turbines, emergency engines) and offsite travel (delivery trucks and power plants).
Peak daily construction emissions associated with meeting specified PAR 1110.2 requirements by the specified compliance dates.
PM10 includes PM2.5. PM2.5 emissions were estimated using the CEIDARS PM10 to PM2.5 fraction by combustion source and fuel type.

Table 4-40
Net Remaining Criteria Emissions from Non-biogas Facilities and the Microturbines at Digester Gas Facilities and LNG Facilities at Landfills Compliance Option for Biogas Facilities

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5 lb/day
2008	~~9,089~~ 9,094	~~53,909~~ 53,942	~~2,470~~ 2,479	~~544~~ 545	~~877~~ 878	~~875~~ 876
2009	~~6,410~~ 6,415	~~22,399~~ 22,432	~~1,790~~ 1,799	~~543~~ 544	~~858~~ 859	~~856~~ 857
2010	~~5,964~~ 5,969	~~17,357~~ 17,390	~~1,298~~ 1,307	~~534~~ 535	~~844~~ 845	~~842~~ 843
2011	~~6,072~~ 6,077	~~13,779~~ 13,812	~~1,295~~ 1,304	~~529~~ 530	~~872~~ 873	~~857~~ 858
2012	4,358	6,245	629	211	805	791
2014	3,989	6,075	578	211	773	771

Table includes construction and operational emissions. Construction emission included both biogas and non-biogas emissions from on-site (construction equipment, fugitive dust) and off-site travel. Operational emissions include biogas and non-biogas emissions from on-site (microturbines, emergency engines) and offsite travel (delivery trucks and power plants).
Peak daily construction emissions associated with meeting specified PAR 1110.2 requirements by the specified compliance dates.
PM10 includes PM2.5. PM2.5 emissions were estimated using the CEIDARS PM10 to PM2.5 fraction by combustion source and fuel type.

Tables 4-41 through 4-45 show the net emissions effect taking into consideration emissions reductions from affected equipment reducing emissions to comply with PAR 1110.2 and increased construction emissions from installing air pollution control and monitoring equipment or installing alternative compliance technologies. The tables take into account all secondary adverse operational air quality impacts described in the above subsections. Table 4-41 shows the net emissions effect by compliance year and construction emissions for the compliance option of all biogas plant operators retrofitting using SCR. Table 4-42 shows the net emissions effect by compliance year and construction emissions for the compliance option of all biogas plant operators replacing ICEs with gas turbines. Table 4-43 shows the net emissions effect by compliance year and construction emissions for the compliance option of biogas operators replacing ICEs with microturbines. Table 4-44 shows the net emissions effect by compliance year and construction emissions for the compliance option of biogas operators replacing ICEs with digester plant and LNG plants at landfills. Table 4-45 shows the net emissions effect by compliance year and construction emissions for the compliance option of operators replacing ICEs with microturbines and landfill gas facility operators replacing ICEs with LNG plants. Finally, the net emissions effect for the year 2014 for each of the scenarios is shown in Tables 4-41 through 4-45 because this is the first year that SCR catalysts are expected to be replaced, based on a three-year operating life. Construction will be completed by 2012 so no construction emissions are included in the year 2014. Secondary air quality impacts, as described in previous sections, are included since these will be ongoing.

Table 4-41
Net Criteria Emission Effects from Non-Biogas Facilities and Installing SCR at All Biogas Plants -Total Compared to Baseline

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5 lb/day
2008	~~(106)~~	~~(334)~~	~~(23)~~	~~(7.4)~~	~~0.1~~	~~0.4~~
	(100)	(301)	(14)	(6.8)	1.0	0.7
2009	~~(3,231)~~	~~(36,886)~~	~~(1,195)~~	~~(17)~~	~~(33)~~	~~(33)~~
	(3,225)	(36,853)	(1,186)	(17)	(32)	(32)
2010	~~(3,231)~~	~~(36,886)~~	~~(1,195)~~	~~(17)~~	~~(33)~~	~~(33)~~
	(3,225)	(36,853)	(1,186)	(17)	(32)	(32)
2011	~~(3,603)~~	~~(40,662)~~	~~(1,256)~~	~~(23)~~	~~(43)~~	~~(44)~~
	(3,598)	(40,629)	(1,247)	(22)	(42)	(43)
2012	(5,017)	(40,798)	(1,476)	(13)	(44)	(44)
2014	(5,011)	(40,802)	(1,477)	(13)	(44)	(44)
Positive Emissions Increase						
Operational Significance Thresholds*	55	550	55	150	150	55
Significant?	No	No	No	No	No	No

Values in parentheses are negative values
Table includes construction and operational emissions. Construction emission included both biogas and non-biogas emissions from on-site (construction equipment, fugitive dust) and off-site travel. Operational emissions include biogas and non-biogas emissions from on-site (ICE) and offsite travel (delivery trucks).
Peak daily construction emissions associated with meeting specified PAR 1110.2 requirements by the specified compliance dates.
PM10 includes PM2.5. PM2.5 emissions were estimated using the CEIDARS PM10 to PM2.5 fraction by combustion source and fuel type.
* When construction and operation phases overlap, SCAQMD policy is to use the operational significance thresholds to determine significance.

Table 4-42
Criteria Net Emission Effects from Non-Biogas Facilities and Gas Turbines at All Biogas Plants -Total Compared to Baseline

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5 lb/day
2008	~~(106)~~	~~(334)~~	~~(23)~~	~~(7.5)~~	~~0.1~~	~~0.4~~
	(100)	(301)	(14)	(6.8)	1.0	0.7
2009	~~(3,231)~~	~~(36,886)~~	~~(1,194)~~	~~(18)~~	~~(33)~~	~~(33)~~
	(3,225)	(36,853)	(1,186)	(17)	(32)	(32)
2010	~~(3,231)~~	~~(36,886)~~	~~(1,195)~~	~~(18)~~	~~(33)~~	~~(33)~~
	(3,225)	(36,853)	(1,186)	(17)	(32)	(32)
2011	~~(3,609)~~	~~(40,664)~~	~~(1,256)~~	~~(23)~~	~~(43)~~	~~(44)~~
	(3,603)	(40,631)	(1,247)	(22)	(43)	(43)
2012	(4,317)	(46,863)	(1,954)	(13)	142	142
2014	(4,311)	(46,868)	(1,955)	(13)	142	142
Positive Emissions Increase					142	142
Operational Significance Thresholds*	55	550	55	150	150	55
Significant?	No	No	No	No	No	Yes

Values in parentheses are negative values
Table includes construction and operational emissions. Construction emission included both biogas and non-biogas emissions from on-site (construction equipment, fugitive dust) and off-site travel. Operational emissions include biogas and non-biogas emissions from on-site (gas turbines, emergency engines) and offsite travel (delivery trucks and power plants).
Peak daily construction emissions associated with meeting specified PAR 1110.2 requirements by the specified compliance dates.
PM10 includes PM2.5. PM2.5 emissions were estimated using the CEIDARS PM10 to PM2.5 fraction by combustion source and fuel type.
* When construction and operation phases overlap, SCAQMD policy is to use the operational significance thresholds to determine significance.

Table 4-43
Net Criteria Emission Effects from Non-Biogas Facilities and Microturbines at All Biogas Plants -Total Compared to Baseline

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5 lb/day
2008	~~(106)~~	~~(334)~~	~~(22)~~	~~(7.5)~~	~~(0.1)~~	~~0.4~~
	(100)	(301)	(14)	(6.9)	0.8	0.4
2009	~~(3,231)~~	~~(36,886)~~	~~(1,194)~~	~~(18)~~	~~(33)~~	~~(33)~~
	(3,225)	(36,853)	(1,186)	(17)	(32)	(32)
2010	~~(3,231)~~	~~(36,886)~~	~~(1,194)~~	~~(18)~~	~~(33)~~	~~(33)~~
	(3,225)	(36,853)	(1,186)	(17)	(32)	(32)
2011	~~(3,609)~~	~~(40,664)~~	~~(1,256)~~	~~(23)~~	~~(43)~~	~~(44)~~
	(3,603)	(40,631)	(1,247)	(22)	(43)	(43)
2012	(5,282)	(48,051)	(1,848)	(13)	(117)	(117)
2014	(5,275)	(48,056)	(1,850)	(13)	(117)	(117)
Positive Emissions Increase						
Operational Significance Thresholds*	55	550	55	150	150	55
Significant?	No	No	No	No	No	No

Values in parentheses are negative values
Table includes construction and operational emissions. Construction emission included both biogas and non-biogas emissions from on-site (construction equipment, fugitive dust) and off-site travel. Operational emissions include biogas and non-biogas emissions from on-site (microturbines, emergency engines) and offsite travel (delivery trucks and power plants).
Peak daily construction emissions associated with meeting specified PAR 1110.2 requirements by the specified compliance dates.
PM10 includes PM2.5. PM2.5 emissions were estimated using the CEIDARS PM10 to PM2.5 fraction by combustion source and fuel type.
* When construction and operation phases overlap, SCAQMD policy is to use the operational significance thresholds to determine significance.

Table 4-44
Net Criteria Emission Effects from Non-Biogas Facilities and Gas Turbines at Digester Gas Facilities and LNG Facilities at Landfills -Total Compared to Baseline

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5 lb/day
2008	~~(106)~~	~~(334)~~	~~(22)~~	~~(7.5)~~	~~(0.1)~~	~~0.4~~
	(100)	(301)	(14)	(6.9)	0.8	0.4
2009	~~(3,231)~~	~~(36,886)~~	~~(1,194)~~	~~(18)~~	~~(33)~~	~~(33)~~
	(3,225)	(36,853)	(1,186)	(17)	(32)	(32)
2010	~~(3,231)~~	~~(36,886)~~	~~(1,195)~~	~~(17)~~	~~(33)~~	~~(33)~~
	(3,225)	(36,853)	(1,186)	(17)	(32)	(32)
2011	~~(3,123)~~	~~(40,464)~~	~~(1,198)~~	~~(22)~~	~~(5)~~	~~(18)~~
	(3,117)	(40,431)	(1,189)	(22)	(4)	(17)
2012	(4,453)	(47,533)	(1,909)	(340)	33.7	21.3
2014	(4,821)	(47,703)	(1,960)	(340)	1.2	0.75
Positive Emissions Increase					33.7	21.3
Operational Significance Thresholds*	55	550	55	150	150	55
Significant?	No	No	No	No	No	No

Values in parentheses are negative values
Table includes construction and operational emissions. Construction emission included both biogas and non-biogas emissions from on-site (construction equipment, fugitive dust) and off-site travel. Operational emissions include biogas and non-biogas emissions from on-site (gas turbines, emergency engines) and offsite travel (delivery trucks and power plants).
Peak daily construction emissions associated with meeting specified PAR 1110.2 requirements by the specified compliance dates.
PM10 includes PM2.5. PM2.5 emissions were estimated using the CEIDARS PM10 to PM2.5 fraction by combustion source and fuel type.
* When construction and operation phases overlap, SCAQMD policy is to use the operational significance thresholds to determine significance.

Table 4-45
Net Criteria Emission Effects from Non-Biogas Facilities and Microturbines at Digester Gas Facilities and LNG Facilities at Landfills -Total Compared to Baseline

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5 lb/day
2008	~~(106)~~	~~(334)~~	~~(22)~~	~~(7.5)~~	~~(0.1)~~	~~0.4~~
	(100)	(301)	(14)	(6.9)	0.8	0.4
2009	~~(3,231)~~	~~(36,886)~~	~~(1,194)~~	~~(18)~~	~~(33)~~	~~(33)~~
	(3,225)	(36,853)	(1,186)	(17)	(32)	(32)
2010	~~(3,231)~~	~~(36,886)~~	~~(1,195)~~	~~(17)~~	~~(33)~~	~~(33)~~
	(3,225)	(36,853)	(1,186)	(17)	(32)	(32)
2011	~~(3,123)~~	~~(40,464)~~	~~(1,198)~~	~~(22)~~	~~(5)~~	~~(18)~~
	(3,117)	(40,431)	(1,189)	(22)	(4)	(17)
2012	(4,837)	(47,998)	(1,864)	(340)	(72)	(84)
2014	(5,205)	(48,168)	(1,914)	(340)	(104)	(104)
Positive Emissions Increase						
Operational Significance Thresholds*	55	550	55	150	150	55
Significant?	No	No	No	No	No	No

Values in parentheses are negative values
Table includes construction and operational emissions. Construction emission included both biogas and non-biogas emissions from on-site (construction equipment, fugitive dust) and off-site travel. Operational emissions include biogas and non-biogas emissions from on-site (microturbines, emergency engines) and offsite travel (delivery trucks and power plants).
Peak daily construction emissions associated with meeting specified PAR 1110.2 requirements by the specified compliance dates.
PM10 includes PM2.5. PM2.5 emissions were estimated using the CEIDARS PM10 to PM2.5 fraction by combustion source and fuel type.
* When construction and operation phases overlap, SCAQMD policy is to use the operational significance thresholds to determine significance.

As shown in Table 4-42, the compliance option in which all biogas facility operators replace ICEs with gas turbines would exceed the regional operational significance threshold for PM2.5 in the years 2012 and 2014. As shown in Tables 4-44 through 4-48, implementing PAR is not expected to result in an exceedance of any operational significance thresholds for VOC emissions or any other criteria pollutants.

Toxic Air Contaminant Impacts

Operational Toxic Air Contaminant Emissions

Adverse health risk effects are estimated by evaluating the impact of toxic air contaminants (TACs) upon receptors surrounding a TAC emissions source. Carcinogenic and chronic noncarcinogenic impacts are evaluated from sources that generate TACs with carcinogenic and chronic noncarcinogenic health risk values consistently over a long period of time (e.g., 70 years for sensitive receptors or 40 years for occupational receptors.). Acute impacts are evaluated from TACs with acute noncarcinogenic health risk values over a short period of time (one hour).

PM emissions from diesel exhaust have carcinogenic and chronic noncarcinogenic health effects. No acute noncarcinogenic health risk values have been established for diesel exhaust. Diesel PM10 carcinogenic health risks are evaluated from mobile sources, i.e., emissions diesel truck delivery trips and from stationary sources, i.e., emissions from emergency backup generators. Health effects from diesel particulates emitted from these two primary sources are evaluated in the following subsections. Chronic and acute non-carcinogenic health risks were examined for ammonia slip from the two largest biogas facilities.

Diesel Delivery Truck Trips

Diesel Delivery Truck Trips to LNG Facilities: The LNG facilities have the potential to generate diesel delivery truck trips because of the need to transport LNG to potential customers off-site. However, as noted previously, only the landfill gas operations are expected to be able to replace ICEs with LNG facilities because of the large space requirements of LNG facilities.

It is estimated that a facility generating the largest volume of LNG would generate approximately 4,715,897 gallons of LNG per year. Based on this volume and a standard LNG truck carrying capacity of 10,000 gallons per truck, approximately 472 annual truck trips would be required. Because these facilities need to pre-treat the landfill gas, an additional four truck trips per year (once every three months) would be required to remove carbon from the pretreatment filter and another four truck trips would be necessary to deliver replacement carbon. One truck would be needed to remove catalyst and one to deliver catalyst. Assuming that trucks idle for 15 minutes per trip at the facility (five minutes at the gate, five minutes before delivery and five minutes after delivery), the health risk from diesel exhaust for a sensitive or residential receptor 25 meters away would be 2.0×10^{-9}, which is less the SCAQMD's cancer risk significance threshold of ten in one million (10×10^{-6}). Similarly, the greatest chronic hazard index level from diesel exhaust PM from diesel deliver trucks would be 1.3×10^{-3}, which is well below the chronic hazard index significance threshold of 1.0. Additional information regarding this analysis can be found Appendix C.

Diesel Delivery Truck Trips to Digester Gas Facilities: Facility operators who retrofit existing equipment with SCR control equipment are not expected to need new emergency backup engines. As a result, no additional diesel truck trips would be generated by these facilities. Since landfill gas operations are not expected to need emergency backup engines and can flare landfill gas in the event of power outages, no carcinogenic risks from diesel emergency engines were assumed to occur. Diesel emergency engines are expected to be needed at digester gas facilities to operate pumps or compressors. Truck trips to digester gas facilities would be necessary to supply diesel fuel. While at total of 178 diesel truck trips may occur in one year for all affected facilities, the number of diesel truck delivery trips to a specific facility is expected to be less than two per year, which is expected to be less than the carcinogenic significance threshold.

Diesel Emergency Backup Generators

Biogas Facilities: Facility operators who replace natural gas ICEs with electric motors and diesel emergency generators would operate a maximum of 50 hours per year with commensurate diesel exhaust particulate matter emissions per year.

It is expected that operators of digester plants where ICEs are either replaced by alternative compliance technologies or add-on control technology is applied, would need emergency backup generators to make-up electricity loss by either the difference in efficiency between the existing ICE and alternative technologies or pressure losses from add-on control technology. A health risk analysis was completed for diesel exhaust particulate matter from the two biogas facilities that are expected to emit the most diesel particulate matter exhaust. The largest facility operates four 4,166 bhp digester gas engines; the other operates two 3471 bhp digester gas engines. It was assumed that the emergency engines would be placed in the same location as the existing natural gas engines and that the emission parameters would be similar. To be conservative, health risk was estimated from the highest off-site concentration assuming the receptor at that location was a sensitive or residential receptor. At both facilities that receptor is a worker receptor. The greatest carcinogenic health risk generated from the use of diesel fueled emergency generators would be 3.4 in one million (3.4×10^{-6}), which is less than the SCAQMD's cancer risk significance threshold of 10 in one million (10×10^{-6}). The greatest chronic hazard indices from diesel particulate matter exhaust would be 0.002, which is less than the chronic hazard index significance threshold of 1.0. The target organ for diesel exhaust particulate toxicity is the respiratory system. Long-term exposure to diesel exhaust can cause chronic respiratory symptoms and reduced lung function, and may cause or worsen allergic respiratory diseases such as asthma. Additional information regarding this analysis can be found Appendix C.

Non-biogas Facilities: As presented in the criteria pollutant analysis, the peak daily operational emissions assumes that operators of 169 non-biogas engines would replace their engines with electric motors (see Table 4-8) because this is expected to be a less costly compliance option than other compliance options. Further, the analysis assumed that operators of all remaining non-biogas engines, a total of 624 engines, would to comply with PAR 1110.2. It is assumed that: operators of 40 percent of these engines would use the existing engines as emergency generators; operators of 20 percent of these engines would use diesel-fueled emergency engines; and operators of the remaining 40 percent of are not assumed to need an emergency engine. Non-biogas emergency generators have higher power ratings than biogas facilities because biogas emergency engines were sized for the efficiency loss between the existing ICE and the add-on emissions control or ICE alternative technology; where non-biogas emergency engines were sized to generate equivalent electricity or shaft work as the electric motor. The three facilities with the largest facilities are not near residential or sensitive receptors. The health risk at the worker receptors near these facilities are below the significance threshold of one in a million. However, the facility with engines with the fourth largest net horsepower would generate a health risk of 18 in one million (1.8×10^{-5}), which is greater than the significance threshold of 10 in a million (1×10^{-5}). The facility has six 634 bhp natural gas engines used to run pumps. The facility with engines with the fourth largest net horsepower would have a chronic non-carcinogenic health risk of 0.014. The chronic non-carcinogenic health risk from these facilities is much less than the significance threshold of 1.0.

Ammonia Slip Emissions

Facility operators may install SCR or NOxTech control systems on existing ICEs as possible compliance options. Both technologies can use either urea or aqueous ammonia to control NOx emissions. The amount of slip is expected to be independent of whether urea or ammonia is used.

Ammonia, though not a carcinogen, can have chronic and acute health impacts. Staff estimates approximately 3.64 pounds of ammonia per brake horsepower would be required to reduce NOx. Similar to the above analysis of diesel particulate matter exhaust health risk analysis, health risks from ammonia were examined at the two facilities with the largest ammonia emissions. The maximum acute hazard index is expected to be 0.4. The greatest chronic hazard index from ammonia at either of the two facilities with the largest ammonia emissions would be 0.97. The target organ for chronic ammonia toxicity is the respiratory system. The target organs for acute ammonia toxicity are the eyes and the respiratory system. Ammonia can cause inflammation of the respiratory tract, which can lead to wheezing, shortness of breath, and chest pain. Inhalation of vapor from concentrated, industrial strength ammonia may cause burns to the respiratory tract. Eye exposure can cause tearing, inflammation, and irritation to temporary or permanent blindness.

Operational Health Risks Conclusions

Health risks are estimated for receptors around a specific source. Health risk from sources at the same facility are additive by type of health risk. Carcinogenic health risks are additive. Non-carcinogenic chronic risks are estimated by target organ and are additive per similar target organ. Non-carcinogenic acute risks are estimated by target organ and are additive per similar target organ. Acute and chronic risks cannot be added together. If facilities are close together (typically within a mile), then the health risk from each facility at receptors shared by the two facilities can be added together.

The preceding cancer and noncancer health risk analyses resulted in the following conclusions. Cancer risk at biogas facilities where operators who would choose to replace existing ICEs with LNG plants from diesel trucks was concluded to be 1.99 x 10^{-9}, which is less the SCAQMD's cancer risk significance threshold of ten in one million (10 x 10^{-6}). Noncancer chronic health risks were concluded to be 0.0013, which is well below the chronic hazard index significance threshold of 1.0. Diesel truck trips to digester gas facilities were expected to have negligible health risk effects.

For facility operators at non-biogas facilities who replace natural gas ICEs with electric motors and diesel emergency backup generators, the maximum cancer risk from installing emergency diesel backup generators is approximately 18 in one million (1.8 x 10^{-5}), which is greater than the significance threshold of 10 in one million (1 x 10^{-5}). The non-carcinogenic chronic hazard index from this facility is 0.014, which is less than the significance threshold of 1.0.

The greatest carcinogenic health risk generated from biogas facilities where operators of digester plants replace ICEs with alternative compliance technologies and use diesel fueled emergency backup generators would be 3.4 in one million (3.4 x 10^{-6}), which is less than the SCAQMD's cancer risk significance threshold of 10 in one million (1 x 10^{-5}). The greatest chronic hazard indices from diesel particulate matter exhaust at this facility would be 0.002, which is less than the chronic hazard index significance threshold of 1.0.

Ammonia, used as a reducing agent in SCR and NOxTech control technologies, though not a carcinogen, can have chronic and acute health impacts resulting from ammonia slip. The maximum acute hazard index from ammonia slip emissions would be 0.4, which is less than the acute hazard index significance threshold of 1.0. Since ammonia is the only toxic in this analysis with an acute effect, PAR 1110.2 would not be significant for acute health risk. The greatest chronic hazard index from ammonia at either of the two facilities with the largest ammonia emissions would be 0.97.

At any single biogas facilities, it was assumed that biogas operators would install the same add-on control technology for all of the biogas engines or remove the existing ICEs and replace them with the same alternative ICE technology (i.e., all gas turbines, microturbines or biogas-to-LNG plant). However, some biogas facilities have both biogas and non-biogas engines at the same location. The worst-case carcinogenic health risk could occur at a facility that had both biogas and non-biogas emergency engines. However, the carcinogenic health risk at the facility with both biogas and non-biogas emergency engines should be below the sum of the health risk of the biogas facility with the largest carcinogenic risk and the non-biogas facility with the largest carcinogenic health risk (3.4 in one million + 18 in one million = 21.4 in one million), which is greater than the significance threshold of ten in a million ($1.0x10^{-5}$).

The sum of the hazard indices of the biogas facility with the largest non-carcinogenic risk and the non-biogas facility with the largest non-carcinogenic health risk would be less than the significance threshold of 1.0 (0.97 +0.014 = 0.98).

Based on the above results, implementing PAR 1110.2 has the potential to generate significant cancer risks, but insignificant acute hazard impacts, and insignificant acute and chronic hazard impacts.

<u>The exemptions would only allow affected facilities to operate at existing levels, there would be no new toxic effects. Some TACs are also considered VOCs. While the VOC limit has increased for new DG engines from the proposal in the Draft EA, the new VOC limits will still be less than the existing BACT limit of 30 ppm VOC; therefore, toxic emission are still expected to be reduced from baseline.</u>

<u>Construction Toxic Emissions</u>

Diesel particulate matter has carcinogenic and chronic non-carcinogenic effects from long-term exposure. Diesel particulate matter does not have acute health risk values. Carcinogenic health risk is estimated over 70 years for sensitive and residential receptors and 40-years for worker receptors. To calculate carcinogenic and chronic non-carcinogenic health risks, annual concentrations data are required. Construction at any facility to comply with the most construction-intensive PAR 1110.2 compliance option (landfill gas to LNG plant) is expected to be limited to no more than 105 days. Construction for other PAR 1110.2 compliance requirements is expected to last one or two days at most. Since the various construction scenarios do not provide one year's worth of concentration data and the exposure duration to construction emissions associated with complying with PAR 1110.2 is much shorter than 70 years (for sensitive receptors) or 40 years (for worker receptors), carcinogenic and chronic non-carcinogenic health risk from construction activities associated with complying with PAR 1110.2 is expected to be less than significant.

Changes to PAR 1110.2 since the Draft EA was release would not require additional construction.

Odor Impacts

Under normal operating and permitted conditions, ammonia slip is approximately five to 10 ppm. Because exhaust gases are hot, any ammonia slip emissions would be quite buoyant and would rapidly rise to higher altitudes without any possibility of lingering at ground level. The odor threshold of ammonia is one to five ppm, but because of the buoyancy of ammonia emissions and an average prevailing wind velocity of six miles per hour in the Basin, it is unlikely that ammonia slip emissions would exceed the odor threshold. Based on the Tier II health risk analysis the highest concentration at the facility with the greatest ammonia slip would be 0.26 ppm which is below the odor threshold of ammonia.

No more than four diesel truck trips are expected at any affected facility per day. Because diesel trucks are limited to five minutes of idling at a single time by state regulation, no adverse odor impacts are expected.

Emergency ICE engines are limited to 50 hours of operation per year for testing. Testing events typically don't last more than 30 minutes and usually no more frequently than once per week. Because of this limitation no odor impacts are expected.

The exemptions would allow affected engines to operate at current levels during emergencies and certain weather conditions; therefore, no new odor emissions are expected. The increases in VOC and CO emission limits for new DG engines would be less than existing BACT for new engines; therefore, PAR 1110.2 would reduce emissions that may cause odors.

Global Warming Impacts

As indicated in Chapter 3, combustion processes generate greenhouse gas (GHG) emissions in addition to criteria pollutants. The following analysis focuses on directly emitted CO2 because this is the primary GHG pollutant emitted during the combustion process and is the GHG pollutant for which emission factors are most readily available. CO2 emissions were estimated using emission factors from CARB's EMFAC2007 and Offroad2007 models and EPA's AP-42.

The analysis of GHGs is a much different analysis than the analysis of criteria pollutants for the following reasons. For criteria pollutants significance thresholds are based on daily emissions because attainment or non-attainment is based on daily exceedances of applicable ambient air quality standards. Further, several ambient air quality standards are based on relatively short-term exposure effects on human health, e.g., one-hour and eight-hour. Since the half-life of CO2 is approximately 100 years, for example, the effects of GHGs are longer-term, affecting global climate over a relatively long time frame. As a result, the SCAQMD current position is to evaluate GHG effects over a longer timeframe than a single day. Although GHG emissions are typically considered to be cumulative impacts because they contribute to global climate effects, this ~~Draft~~Final EA for PAR 1110.2 analyzed the GHG emissions as project specific impacts because of the close relationship between CO and CO2 emissions from compliance options. For example, installation of oxidation catalyst to reduce CO emissions has the potential to increase CO2 emissions. Alternatively, replacing ICEs with electric motors reduces direct CO2 emissions, while incrementally increasing CO2 emissions from utility power generating equipment.

SCAQMD staff assumed for the CEQA analysis, that for some categories of ICEs, it may be less costly to install electric motors than comply with PAR 1110.2. SCAQMD staff identified 225 ICEs were it would be less costly to install electric motors (see Table 4-8). To provide a conservative analysis, staff assumed that operators of only 75 percent of these engines, 169 engines, would install electric motors. Electric motors are estimated to have a lifespan of 10 years. For the purposes of addressing the GHG impacts of PAR 1110.2, the overall impacts of CO2 emissions from the project were estimated and evaluated from initial implementation of the proposed project in 2009 through 2019 (i.e., over the lifespan of the electric motors). While the analysis was only completed over the lifespan of the electric motor, it is expected that the reduction would continue, since facility operators would be expected to replace electric motors with another electric motor once the original is replaced.

The analysis estimated CO2 emissions from all sources (primary and secondary, construction and operation) from the beginning of the proposed project to the end of the project. The beginning of the proposed project would be 2009, since it was assumed that electric motors would be install starting in 2009. The end of the proposed project for this analysis is the 2018, which correlates to the useful life of an electric motor. With electric motors the proposed project would have a reduction in CO2 over the ten years. Without the electric motors in the proposed project there would be an increase in CO2 over the same time frame.

Exceptions added to PAR 1110.2 since the release of the Draft EA would allow affected engines to operate at existing levels during emergencies and certain weather conditions; therefore, no new CO2 emissions would be generated. VOC and CO emissions limits for new DG engines have increased; however, the lower emissions would have been achieved either by more efficient combustion or add-on control technology. More efficient combustion and add-on control technology would covert CO to CO2. Since more CO would be allowed, less CO2 would be emitted. Therefore, the changes to PAR 1110.2 since the Draft EA would only reduce the amount of CO2 generated.

Minimum Number of ICEs That Are Required to Prevent a Net Increase in CO2 from PAR 1110.2

Since the proposed project would generate CO2 without replacement of some non-biogas engines with electric motors, SCAQMD staff estimated the minimum number of non-biogas engines that would need to be replaced in order prevent a net CO2 increase. The analysis was based on average CO2 emissions per engine. Staff believes this to be a conservative approach since larger and more heavily used engines are more likely to be electrified. To prevent a net increase in CO2 emissions, approximately 15 of the 225 non-biogas ICEs that are expected to have lower cost by replacing ICEs with electric motors than complying with PAR 1110.2 requirements would need to be replaced with electric motors. This is summarized in Table 4-49. A description of worst-case compliance option is included in the first column. The second column shows the CO_2 emission reductions for the project with electric motors. The third column present the CO_2 emission increases without electric motors. The fourth column shows the CO_2 reductions that would occur with the electric motors. The fifth column shows the average CO_2 savings per electric motor. The last column presents the number of electric motors that would be required for a reduction of CO_2 emissions.

Conclusion

Based on the above air quality analysis, implementing PAR 1110.2 is expected to generate overlapping operational and construction emissions that have the potential to exceed the operational directly emitted PM2.5 significance threshold by 25 pounds (142 pounds per day – 55 pound per day PM2.5 significance threshold, see Table 4-42) for the gas turbine biogas compliance option. PAR 1110.2 would also be significant for carcinogenic health risk from diesel emergency engines during operations at non-biogas facilities. Therefore, PAR 1110.2 is significant for air quality for operational and construction criteria pollutants and carcinogenic health risk. Because of the expected replacement of some non-biogas engines with electric motors, CO_2 emissions are expected to be reduced by PAR 1110.2.

Table 4-46
Average Number of ICE Engines Replaced with Electric Motors Needed for CO2 Reductions under the Worst-Case (Gas Turbines)

Gas Turbines – CO2 Reductions

Description	Proposed Project CO2, ton/year	No Electrification CO2, ton/year	Reduction in CO2 from Electrification	Average CO2 Savings per Motor	Average No of Motor for CO2 Reductions
Baseline					
2008	(22,186)	(22,181)	5		
2009	121,080	(23,358)	18,614		
2010	(41,973)	(23,358)	18,614		
2011	(52,600)	(21,905)	30,695		
2012	(18,703)	11,236	29,938		
2014	(18,776)	11,163	29,938		
2013-2018	(112,654)	66,976	179,630		
10 year total	(104,849)	9,591	114,439	677	15

Electric motors were assumed to have a ten year lifespan (2009 the expected start date of ICE replacement with electric motors to 2019).

It is possible that fewer than 169 non-biogas engines could be replaced with electric motors, but, given the lower costs of installing and operating electric motors, it is likely that at least 15 non-biogas engines or more would be replaced with electric motors.

<u>Exceptions and increase in VOC and CO emission limits for new engines added to PAR 1110.2 since the release of the Draft EA would allow affected engines to operate at existing levels during emergencies and certain weather conditions; therefore, no new adverse air</u>

quality impacts were identified. Based on the above analysis, the new exceptions and increase in VOC and CO emission limits for new engines would not make an adverse air quality impact that was identified as not significant, significant; nor make an adverse air quality impact that was already identified as significant in the Draft EA substantially worse.

Project Specific Mitigation Measures: PM2.5 emissions contributing the to the criteria pollutant significance determination are generated by gas turbines, if this compliance option is chosen instead of complying with biogas requirements of PAR 1110.2. In addition, secondary PM2.5 emissions from emergency diesel backup generators gas turbines and for electric motors installed at non-biogas facilities, diesel trucks transporting materials, e.g., catalyst, activated carbon, etc., to and from affected facilities, and power plant emissions would occur. Based on the gas turbine biogas compliance option, PAR 1110.2 has the potential to emit 142 pounds of PM2.5 per day.

New gas turbines installed as a compliance option instead of complying with PAR 1110.2 would likely be subject to Rule 1303 or Rule 2005 BACT requirements. No add-control technology has been identified to reduce PM2.5 emissions from gas turbines.

Emergency diesel backup generators installed at non-biogas facilities would likely be subject to particulate requirements of Rule 1470. The analysis of air quality impacts assumed that emergency diesel backup generators would comply with Rule 1470 requirements, cancer risk was still significant under the gas turbine compliance options (see Table 4-42). To further reduce diesel PM emissions diesel particulate filters (DPFs) will be required for any emergency diesel backup generators used at non-biogas facilities where operators install electric motors and the carcinogenic health risk exceeds 10 in one million ($1x10^{-5}$). DPFs allow exhaust gases to pass through the filter medium, but trap diesel PM. Depending on engine baseline emissions and emission test method or duty cycle, DPFs can achieve a PM emission reduction of greater than 85 percent. In addition, DPFs can reduce HC emissions by 95 percent and CO emissions by 90 percent. Limited test data indicate that DPFs can also reduce NOx emissions by six to ten percent. Most DPFs require periodic regeneration, most commonly achieved by burning off accumulated diesel PM. There are both active DPFs and passive DPFs. Active DPFs use heat generated by means other than exhaust gases (e.g., electricity, fuel burners, microwaves, and additional fuel injection to increase exhaust gas temperatures) to assist in the regeneration process. Passive DPFs, which do not require an external heat source to regenerate, incorporate a catalytic material, typically a platinum group metal, to assist in oxidizing trapped diesel PM. Although there is a slight increase in directly emitted NO_2 during the regeneration of passive DPFs, overall there is ultimately a net reduction in NO_2 emissions. Many engines can also limit their testing to be less than 30 hours per year to reduce carcinogenic health risk to below 10 in one million.

Since facility operators typically do not own the diesel delivery trucks, no mitigation is available to reduce the significant carcinogenic health risk from diesel delivery trucks.

The exceptions and increase in VOC and CO emission limits for new engines added to the proposed project after the Draft EA was circulated for public review do not make adverse air quality impacts, identified in the Draft EA as not significant, significant; nor substantially

<u>increase the severity of an air quality topic that was identified as significant in the Draft EA. In addition, the exceptions and increase in VOC and CO emission limits for new engines would not make an air quality topic that was identified as mitigated to not significant, significant; nor substantially increase the severity of an air quality topic that was mitigated, but still significant in the Draft EA.</u>

<u>Remaining Air Quality Impacts</u>: Based on a PM control efficiency of 85 percent from installing DPFs on emergency diesel backup generators, it is expected that PM2.5 emission impacts from gas turbines, delivery trucks and diesel emergency backup generators would remain significant. DPFs are only expected to reduce PM2.5 emissions from emergency diesel backup generators by approximately one pound per day. DPFs installed on diesel backup generators are, however, expected to reduce significant adverse cancer risks to less than significant. The maximum cancer risk at the largest non-biogas facility can be reduced from approximately 18 in one million (1.8×10^{-5}) to approximately 4.5 in one million (4.5×10^{-6}), which is less than the SCAQMD's cancer risk significance threshold of 10 in one million (1.0×10^{-5}). Even if the carcinogenic heath risk from both the biogas and non-biogas facilities were added together (21.4 in one million or 2.14×10^{-5}), DPF would reduce the carcinogenic health risk to less than significant ($2.14 \times 10^{-5} \times (1-0.85) = 3.21$ in one million).

<u>The exceptions and increase in VOC and CO emission limits for new engines added after the Draft EA was circulated for public review would not substantially alter the remaining air quality impacts or generate new remaining air quality impacts.</u>

<u>Cumulative Air Quality Impacts</u>: The preceding analysis concluded that project-specific PM2.5 emissions from overlapping construction and operational activities for the gas turbine control option component of the proposed project would be significant because the SCAQMD's operational significance threshold for PM2.5 would be exceeded. However, PAR 1110.2 is part of a comprehensive ongoing regulatory program that includes implementing related SCAQMD 2007 AQMP control measures as amended or new rules to attain and maintain with a margin of safety all state and national ambient air quality standards for all areas within its jurisdiction. Only the compliance option that includes replacing all biogas engines with gas turbines would generate significant PM2.5 emissions. No other compliance options would result in significant adverse regional air quality impacts for any criteria or precursor pollutants. Since no other compliance option exceeds any project-specific regional significance thresholds, they are not considered to be cumulatively considerable. Although the gas turbine compliance option would exceed the project-specific PM2.5 operational significance threshold, it is also expected to generate 4,311 pounds of NOx reductions per day and 1,955 pounds of VOC reductions per day. Both NOx and VOCs are precursors to PM2.5. According to the 2007 AQMP, the NOx equivalency factor for PM2.5 is 9.9 tons per day per ton of PM2.5 and the VOC equivalency factor for PM2.5 would be 23.0 tons per day per ton of PM2.5. This means that reducing one ton of NOx per day is equivalent to reducing 0.1 ton per day of PM2.5 and reducing on ton of VOC is equivalent to reducing 0.04 tons per day of PM2.5. Therefore, the large reductions in NOx and VOC emissions from the gas turbines would more than make up for any increases in direct PM2.5 emissions. Based on this rationale, PM2.5 emissions from the gas turbine scenario are not considered to be cumulatively considerable. Therefore, PAR 1110.2 would not be cumulatively significant for PM2.5.

Relative to GHGs, implementing PAR 1110.2 is expected to reduce CO2 emissions. Therefore, implementing PAR 1110.2 is not expected to generate significant adverse cumulative criteria or GHG air quality impacts.

As noted in the air toxics analysis, project-specific carcinogenic health risk from PAR 1110.2 can be mitigated to less than significant. Since air toxics create localized effects and no facilities regulated by PAR 1110.2 are within two miles of each other, implementing PAR 1110.2 is not expected to create significant adverse cumulative carcinogenic health risks.

<u>Since the exemptions and increase in VOC and CO emission limits for new engines that were added after the Draft EA was circulated for public review were not determined to generate new project-specific adverse impacts, nor substantially increase the severity of adverse impacts that were already identified as significant; the new exceptions were not generate new cumulative adverse impacts or make adverse cumulative impacts already identified substantially worse.</u>

<u>**Cumulative Air Quality Impact Mitigation**</u>: As indicated in the preceding discussion, no significant adverse cumulative air quality impacts were identified, therefore, no cumulative impact mitigation measures are required.

Energy

<u>**Significance Criteria**</u>

Impacts to energy resources will be considered significant if any of the following criteria are met:

- The project conflicts with adopted energy conservation plans or standards.
- The project results in substantial depletion of existing energy resource supplies.
- An increase in demand for utilities impacts the current capacities of the electric and natural gas utilities.
- The project uses non-renewable energy resources in a wasteful and/or inefficient manner.

<u>**New, Retrofit or Replacement Equipment for ICEs**</u>

An analysis was completed in the NOP/IS demonstrating that implementing PAR 1110.2 would not significantly adversely affect natural gas and electrical resources. However, based on comments received on the NOP/IS, potential adverse energy resources impacts from flaring and installing alternative technologies at biogas facilities instead of complying directly with PAR 1110.2 are analyzed in the following subsections.

PAR 1110.2 would require the construction and operation of control devices and monitoring equipment for both non-biogas and biogas facilities. The construction and operational phases would each have adverse energy impacts. Since construction and operation would overlap the concurrent effect of the construction and operational adverse impacts will be analyzed together.

Electricity Effects

2005 Baseline

The existing engines can be categorized as distributed generators and non-distributed generators. The non-distributed generators do not generate electricity for the facility at which they are located. These ICE instead produce work for pumps or compressors.

Distributed generators produce electricity for the facility at which they are located. Some distributed generators produce electricity for on-site activities. Others generate electricity for on-site activities; any additional energy is sold to the power grid.

The amount of electricity generated at existing facilities was estimated from the amount of fuel reported to the SCAQMD in the facility surveys. The total amount of electricity was estimated by the ratio of responses and the total number of PAR 1110.2 facilities in the SCAQMD permit database. Based on the SCAQMD inventory and survey data approximately 437,214 MW-hours per year were generated in 2005.

Construction

SCAQMD staff assumed that all construction equipment would be diesel fuel. Therefore, there would be no additional electricity required. It is possible that welding may be performed with electricity from the power grid. However, because many of the existing engines are distributed generators, it is likely that electricity would not be available for construction. In addition, the electricity consumption for welders is expected to be small and short in duration. Therefore, no adverse electrical impacts are expected from construction of monitoring or control equipment.

Exceptions added to PAR 1110.2 since the release of the Draft EA would allow affected engines to operate at existing levels during emergencies and certain weather conditions; therefore, no new construction would be required. The increase in VOC and CO emission limits for new engines are not expected to alter the use of electricity in the construction of new diesel engine projects.

Operations

Non-biogas Add-on Control and Monitoring Equipment

The additional monitoring and control equipment may require electricity from the existing ICE, ICE replacement or grid to operate. It was assumed that little electricity would be required for CO analyzers, AFRCs and add-on control equipment. CEMS systems were assumed to require 2.3 kW per CEMS. Based on this, approximately 511 MW-hours per year would be required for monitoring equipment.

Biogas Add-on Control or ICE Alternative

The proposed requirement to install CEMS systems on specified engines would be expected to increase demand for electricity. Based on the facilities survey, SCAQMD staff estimates that 56 MW-hr of electricity would be required to operate the additional CEMS systems.

Approximately 28 biogas facilities are expected to either need add-on control, such as SCR or NOxTech systems or to replace existing biogas ICEs with alternative technologies, such as turbines, microturbines, fuel cells, boilers, or LNG plants.

SCR, NOx Tech Control Technologies

SCR and NOxTech control technologies are expected to slightly reduce the efficiency of some ICEs due to pressure drops caused by the control devices and the need to use digester gas or natural gas to heat elements of the control technologies. The primary effect of this reduction in efficiency is a slight reduction in electricity production from affected ICEs. The electrical production losses (1,706 MWH per year) would be minor compared to alternative compliance options as explained in the following paragraphs.

Turbines, Microturbines, Fuel Cells and Boilers

Replacing ICEs with turbines, microturbines fuel cells and boilers would still allow operators at biogas facilities to generate electricity. Turbines, microturbines and boilers generate more waste heat than ICEs. Therefore, replacing ICEs with turbines, microturbines and boilers would reduce the amount of electricity generated. It is believed that most biogas facilities would be able to support gas turbines, microturbines, fuel cells or boilers; however, some digester gas facilities may not have the space (facility lot size) to support these ICE alternatives.

Electrical efficiency measures the amount of electrical energy produced per unit fuel energy input relative to the energy that is lost to heat or mechanical losses. Boilers are approximately 32 percent energy efficient. ICEs are approximately 31 percent energy efficient. Gas turbines are approximately 26 percent energy efficient and microturbines are approximately 23 percent energy efficient. Since turbines and microturbines are the least energy efficient option and the actual amount of space at digester gas facilities is unknown, turbines and microturbines would represent the "worst-case" loss of electricity production from removing ICEs at biogas facilities. There would be a 57,161 MWH per year reduction in electricity from gas turbines, and a 101,013 MWH per year reduction in electricity from microturbines.

Biogas to LNG Facilities

The existing LNG plant at the Bowerman Landfill includes ICEs to supply electricity to the facility. However, since it is assumed that LNG plants would be an alternative to complying with PAR 1110.2, it was assumed that LNG plants would obtain electricity from the power grid to operate the LNG plants. Therefore, since the ICEs would be removed and electricity would be supplied from the power grid, SCAQMD staff assumes that all electricity production from facilities installing biogas to LNG facilities is lost. The landfill gas would be treated and used off-site as fuel for another system or process. The existing Bowerman Landfill will sell the LNG to the Orange County Transit Authority. Similarly, affected facilities that chose to replace ICEs with LNG plants are expected to sell the LNG for fuel in other processes. Therefore, biogas-to-LNG facilities are expected to generate a new source of LNG that could be used in place of more polluting fuels such as diesel or gasoline.

As noted in the "Air Quality" analysis section, LNG plants require substantial area because of the size and number of components needed to collect, scrub and cool biogas into LNG.

Not all biogas facilities have enough space to support an LNG plant. The analysis of the effects of replacing ICEs with LNG plants includes the following assumptions. Only landfill gas facilities are assumed to have enough area to allow installation of an LNG plant.

The differences in electricity production between the existing ICEs and ICE alternatives are presented in Table 4-50. These differences are based on differences in efficiencies between ICE alternatives and the existing ICEs.

New Exceptions and Increases in VOC and CO Emission Limits for New Engines

Exceptions added to PAR 1110.2 since the release of the Draft EA would allow affected engines to operate at existing levels during emergencies and certain weather conditions; therefore, new adverse electricity impacts would be generated. The increase in VOC and CO emission limits for new engines would not affect the use of electricity; therefore, not new adverse electrical impacts are expected.

Total Electricity Adverse Impacts

Table 4-51 presents the energy production and usage for ICEs retrofitted with applicable control technologies to comply with PAR 1110.2 and for replacing ICEs with alternative technologies. All alternative generate less electricity than the existing ICEs because they are less efficient than ICEs. Biogas-to-LNG plants would not generate any electricity but received electricity from the power grid. However, biogas-to-LNG plants would generate renewable LNG (See Renewable Energy below). Therefore, any compliance option would reduce the total amount of renewable electricity available to the grid.

Table 4-47
Adverse Electricity Impacts from Differences in Efficiency between ICE Alternatives and LNG Reliance on the Power Grid

Description	Electricity Production, MWH/yr	Electricity Consumption, MWH/yr	Total Electricity, MWH/yr	Reduction in Electricity from Baseline, MWH/yr
2005 Baseline (ICE)	437,214		437,214	
SCR	435,509		435,509	1,706
Gas Turbines	380,053		380,053	57,161
Microturbines	336,201		336,201	101,013
Gas Turbines/LNG	155,746	104,694	51,052	386,162
Microturbines/LNG	137,706	104,694	33,081	404,133

ICEs, gas turbines, and microturbines generate electricity.
LNG plants would not generate electricity, but would require energy from the power grid.

Table 4-48
Total Adverse Electricity Impacts from PAR 1110.2

Description	**Non-Biogas and Biogas CEMS and Controllers, MWH/Yr**	**Non-Biogas Electrification, MWH/Yr**	**Electricity Production, MWH/yr**	**Electricity Totals, MWH/yr**	**Reduction in Electricity from Baseline,, MWH/yr**
2005 Baseline			437,214	437,214	0
SCR	(567)	(171,827)	435,509	263,114	(174,100)
Gas Turbines	(567)	(171,827)	380,053	207,659	(229,556)
Microturbines	(567)	(171,827)	336,201	163,807	(273,408)
Gas Turbines/LNG	(567)	(171,827)	51,052	(121,342)	(558,557)
Microturbines/LNG	(567)	(171,827)	33,081	(139,313)	(576,527)

Negative values are presented in parenthesis. Negative electricity values represent consumption, positive values represent production.

According to the Final Program EIR for the 2007 AQMP, 120,194 GW-hours per year were available in southern California in 2002. Table 4-51 shows that 576,527 MW-hour per year would be consumed in a worst-case. A 576,527 MW-hour per year reduction is 0.48 percent of 120,194 GW-hour per year. Since the worst-case PAR 1110.2 scenario would reduce the total amount of electricity available by less one percent, it is not significant for adverse total electricity impacts.

Natural Gas Effects

2005 Baseline

The baseline amount of natural gas of approximately 10,501,630 MMBtu per year (10,028,802 MMBtu per year at non-biogas facilities and 472,828 MMBtu per year at biogas facilities) was estimated from the amount of natural gas use reported in the facility surveys. This information was multiplied by the ratio of total number of Rule 1110.2 facilities to the number of facilities that completed the survey.

Construction

SCAQMD staff assumed that all construction equipment would be diesel fuel. Therefore, there would be no additional natural gas required.

Operations

Non-biogas Add-on Control and Monitoring Equipment

The addition of three way catalyst is expected to result in a pressure drop. The pressure drop would result in an increase in natural gas usage. SCAQMD staff assumed a one-inch pressure drop in the exhaust of an ICE with three way catalyst. The increase in natural gas consumption caused by monitoring equipment is expected to be negligible. Approximately 2,713 MMBtu per year would be consumed because of increased pressure loss.

Limitation of Natural Gas Use on Biogas Engines

PAR 1110.2 would eliminate the efficiency correction factor in 2012. However, between the date of adoption and July 1, 2012, PAR 1110.2 would allow the use of the efficiency correction factor for facility operators who operate engines using 90 percent or more landfill or digester gas. SCAQMD staff expects that most digester gas generators rated greater than 500 bhp would reduce natural gas used to less than 10 percent upon adoption of the rule in 2008 in order to use the efficiency factor. In 2010, the concentration limits for engines comprised of greater than 10 percent biogas would become effective. Biogas engines that use 10 percent or more natural would need to either reduce natural gas to less than 10 percent or meet the 2010 concentration limits. SCAQMD staff expects that the remaining digester gas ICE rated greater than 500 bhp would reduce to less than 10 percent to remain subject to the biogas concentrations. Operators of biogas engines are not expected shut down their engines because of the 90 percent or more landfill or digester gas requirement in subparagraph (d)(1)(B) for the following reasons:

Based on the survey of affected engines conducted by staff, operators of 24 of 26 landfill gas engines use no natural gas. Operators of the remaining two engines use 12 percent natural gas and could reduce this amount to less than 10 percent. Operators of 11 of 27 digester gas engines were reported to use less than 10 percent natural gas. Three more have recently reduced natural gas usage to less than 10 percent. Eleven of the 13 remaining digester gas engines that use more than 10 percent natural gas generate electricity, which means they can either limit their natural gas usage or petition to use a higher percentage of natural gas, if qualified. Operators of the remaining two engines, which drive compressors, may also be eligible to petition for a higher percentage of natural gas usage than 10 percent if they demonstrate that using 10 percent or less natural gas would result in flaring the biogas.

However, while the natural gas will likely be reduced until 2012, SCAQMD staff expects that facility operators will return to the original natural gas consumptions after 2012, since the biogas efficiency correction factor will be eliminated at that time. The reduction of natural gas usage to 10 percent is presented in Table 4-49.

Table 4-49
Reduction of Natural Gas Usage to 10 Percent between 2008 and 2012

Year	Baseline Natural Gas Usage, MMBtu/ year	2008 Natural Gas Reduction, MMBtu/ year	2010 Natural Gas Reduction, MMBtu/ year
2008	4,061,047	162,928	77,761
2010	4,964,605	199,179	95,063

Biogas Add-on Control or ICE Alternative

Approximately 28 biogas facilities are expected to either need add-on control, such as SCR or NOxTech systems or to replace existing biogas ICEs with alternative technologies, such as turbines, microturbines, fuel cells, boilers, or LNG plants.

SCAQMD did not expect a change in the usage of natural gas between the biogas compliance options, except for LNG plants, which are not expected to need natural gas.

<u>The exceptions added after the Draft EA was circulated for public review would allow affected engines to use existing levels of natural gas during emergencies and certain weather</u>

conditions; therefore, no new natural gas usage is expected. The new VOC and CO limits for new DG engines are not expected to increase the amount of natural gas needed.

Emergency Generators

Non-biogas Emergency Generators

There would, however, be a reduction in natural gas usage if facility operators replace ICEs with electric motors. As noted in the analysis of potential air quality impacts from implementing PAR 1110.2, it was assumed that operators of 169 engines at non-biogas facilities would choose to replace their existing engines with electric motors. Staff assumed that 40 percent of these operators would choose to use their existing natural gas engines as emergency backup engines. If 169 non-biogas ICEs are replaced by electric motors, it is estimated that natural gas usage would be reduced by approximately 1,854,358 MMBtu per year. Approximately 1,303,214 MMBtu per year would be consumed at power plants to generate electricity for the 169 existing ICES that would be assumed to be replaced with electric motors. If 40 percent of the 169 existing ICEs use existing natural gas engines for emergency backup, an additional 2,283 MMBtu per year would be needed. A summary of natural gas consumption and reduction associated with non-biogas ICE replacement with electric motors is presented in Table 4-53.

Table 4-50
Natural Gas Consumption and Reduction Associated with Non-biogas ICE Replacement with Electric Motors

Natural Gas Reduction from ICE Replacement with Electric Motors, MMBtu/year	Power Plants Natural Gas Consumption, MMBtu/year	Emergency ICE Natural Gas Consumption, MMBtu/year	Electrification Natural Gas Consumption, MMBtu/year
(1,854,358)	1,303,214	2,283	(548,862)

Values in parentheses are negative. Reduction in natural gas use is negative, consumption is positive

Biogas Emergency Generators

Facility operators that place add-on controls are not expected to need emergency generators because of PAR 1110.2. SCAQMD staff assumed that facility operators might install emergency generators if existing engines were replaced with ICE alternatives. SCAQMD staff assumed that only digester gas facility operators would install emergency generators, since pumps and compressors would be required to be operated continuously. SCAQMD staff assumes that landfill operators would flare landfill gas during emergencies to prevent explosions. In a worst-case (microturbines at all digester plants) approximately 5,023 MMBtu per year of natural gas would be consumed in biogas emergency generators.

Total Natural Gas Impacts

With the replacement of existing non-biogas ICEs with electric motors, PAR 1110.2 would result in an overall reduction in natural gas consumption. The reductions for the proposed project by biogas compliance option are present in Table 4-54.

Exceptions added to PAR 1110.2 since the release of the Draft EA would allow affected engines to operate at existing levels during emergencies and certain weather conditions; therefore, new adverse natural gas impacts would be generated. The increase in VOC and CO emission limits for new engines is not expected to affect the use of natural; therefore, no new adverse natural gas impacts are expected.

Diesel Fuel Effects

2005 Baseline

With the exception of 30 diesel-fueled ICE, the majority of the stationary ICEs subject to PAR 1110.2 are natural gas, biogas or field gas fueled. The 30 diesel fueled ICEs consume approximately 6,363,500 gallons of diesel fuel per year.

Construction

SCAQMD staff assumed that all construction equipment would be diesel fueled. In addition to the construction equipment, delivery and haul trucks would bring supplies and equipment and remove old equipment. The maximum amount of diesel used per day in construction equipment would be 1,761 gallons per day under the biogas compliance options where digester gas facility operators replace ICEs with either turbines or microturbine and landfill gas facility operators replace ICES with LNG plants. The maximum amount of diesel used for construction vehicle travel would be 232 gallons per day for the same scenario.

Table 4-51
Total Adverse Natural Gas Impacts

Description	Catalyst Pressure Drop Consumption, MMBtu/yr	Non-biogas Electrification Natural Gas Consumption, MMBtu/yr	Biogas Emergency Engines Natural Gas, MMBtu/yr	Power Plant Natural Gas, MMBtu/Yr	Biogas Natural Gas Consumption, MMBtu/yr	Non-biogas Natural Gas Consumption, MMBtu/yr	Natural Gas Total, MMBtu/yr	Natural Gas Change from Baseline, MMBtu/yr
Baseline					512,787	10,501,630	11,014,417	
SCR	2,713	(548,862)		1,751	512,787	10,501,630	10,470,019	(544,398)
Gas Turbines	2,713	(548,862)	3,318	68,793	512,787	10,501,630	10,540,378	(474,039)
Microturbines	2,713	(548,862)	5,023	112,645	512,787	10,501,630	10,585,936	(428,481)
Gas Turbines/ LNG	2,713	(548,862)	3,318	397,794	456,430	10,501,630	10,813,022	(201,395)
Microturbines/ LNG	2,713	(548,862)	5,023	415,764	456,430	10,501,630	10,832,698	(181,719)

Values in parentheses are negative. Reduction in natural gas use is negative, consumption is positive

Operation

Vehicle Traffic

Diesel fuel would be consumed by source testing trips, trucks delivering catalysts, ammonia, etc., hauling away spent carbon and catalyst, and trucks hauling LNG offsite to customers. The amount of diesel fuel usage was estimated by the number of affected facilities or material delivered. Diesel fuel use from truck trips associate with PAR 1110.2 are presented in Tables 4-55 through 4-59. Detailed calculations can be found in Appendix C.

Diesel Emergency Generators

An indirect affect of facility operators replacing existing natural gas engines with electric motors and replacing biogas engines with alternative technologies would be the installation of diesel emergency engines to provide power to necessary operations during power failures in the electricity supply grid. Emergency engines were assumed to operate up to 50 hours per year based for testing (maximum allowed per Rule 1470). For this analysis, it was assumed that the brake horsepower rating of the emergency engines installed would be based on increased grid dependence in the case of digester gas generators or would be equivalent to the brake horsepower rating of the existing digester or natural gas work (pump or compressor) engine replaced. The worst-case biogas scenario would require 202 gallons per day of diesel fuel for emergency engines for microturbines used for digester gas facilities and 1,111 gallons per day for emergency generators at non-biogas facilities. Diesel emergency engine ICE fuel consumption is presented in Tables 4-52 through 4-56.

Total Diesel Fuel Adverse Impacts

SCAQMD staff estimates that a maximum of 3,218 gallons of diesel might be consumed per day. The 2007 AQMP states that 10 million gallons of diesel is consumed per day in California. Three thousand, two hundred and eleven gallons of diesel is less than one percent of the 10 million gallons of diesel used in California (0.02 percent). Therefore, the increase in diesel consumption caused by PAR 1110.2 would not be significant. Diesel fuel use from PAR 1110.2 is presented in Tables 4-55 through 4-59. Detailed calculations can be found in Appendix C.

Exceptions added to PAR 1110.2 since the release of the Draft EA would allow affected engines to operate at existing levels during emergencies and certain weather conditions; therefore, new adverse diesel impacts would be generated. The increase in VOC and CO emission limits for new engines would not affect the use of diesel; therefore, no new adverse diesel impacts are expected.

Renewable Energy

Flaring

Representatives of the Landfill Gas to Energy Coalition stated that the cost of installing SCR control equipment to comply with the proposed NOx concentration limits would make flaring gas more economically appealing than installing SCR. They stated further that if the ICEs were removed and landfill gas was flared, PAR 1110.2 could adversely affect California's renewable energy goals.

Table 4-52
Diesel Fuel Use from Truck Trips Associated with Non-biogas Facilities and the SCR Biogas Compliance Option

Year	Daily HHD Consumption Construction, gal/day	Diesel Construction Equipment, gal/day	Daily HHD Consumption Operational gal/day	Non-Biogas Emergency Engines, gal/day	Daily Consumption, gal/day
2008	24	267	9	0	300
2009	20	279	6	65	370
2010	28	373	54	760	1,214
2011	44	653	63	1,111	1,871
2012	8	141	86	1,111	1,346
2014	0	0	149	1,111	1,260
Max	44	653	149	1,111	1,871

HHDT = Heavy – heavy- duty truck

Table 4-53
Diesel Fuel Use from Truck Trips Associated with Non-biogas Facilities and the Gas Turbine Biogas Compliance Option

Year	Daily HHD Consumption Construction, gal/day	Diesel Construction Equipment, gal/day	Daily HHD Consumption Operational gal/day	Non-Biogas Emergency Engines, gal/day	Biogas Emergency Engines, gal/day	Daily Consumption, gal/day
2008	24	267	9	0	0	300
2009	20	367	6	65	0	458
2010	28	373	54	760	0	1,214
2011	44	653	57	1,111	0	1,865
2012	8	141	86	1,111	0	1,346
2014	0	0	149	1,111	140	1,399
Max	44	653	149	1,111	140	1,865

HHDT = Heavy – heavy- duty truck

Table 4-54
Diesel Fuel Use from Truck Trips Associated with Non-biogas Facilities and the Microturbine Biogas Compliance Option

Year	Daily HHD Consumption Construction, gal/day	Diesel Construction Equipment, gal/day	Daily HHD Consumption Operational gal/day	Non-Biogas Emergency Engines, gal/day	Biogas Emergency Engines, gal/day	Daily Consumption, gal/day
2008	24.0	267	9.0	0	0	300
2009	20.0	367	6.0	65	0	458
2010	28.0	373	53.6	760	0	1,214
2011	44.0	653	56.6	1,111	0	1,865
2012	8.0	141	86.4	1,111	0	1,346
2014	0.0	0	149	1,111	202	148.8
Max	44	653	149	1,111	202	1,865

HHDT = Heavy – heavy- duty truck

Table 4-55
Diesel Fuel Use from Truck Trips Associated with Non-biogas Facilities and the LNG and Gas Turbine Biogas Compliance Option

Year	Daily HHD Consumption Construction, gal/day	Diesel Construction Equipment, gal/day	Daily HHD Consumption Operational gal/day	Non-Biogas Emergency Engines, gal/day	Biogas Emergency Engines, gal/day	Daily Consumption, gal/day
2008	24	267	9	0	0	300
2009	20	279	6	65	0	370
2010	28	373	54	760	0	1,214
2011	236	1,761	111	1,111	0	3,218
2012	200	1,249	154	1,111	0	2,714
2014	0	0	281	1,111	140	1,531
Max	236	1,761	281	1,111	140	3,218

HHDT = Heavy – heavy- duty truck

Table 4-56
Diesel Fuel Use from Truck Trips Associated with Non-biogas Facilities and the LNG and Microturbine Biogas Compliance Option

Year	Daily HHD Consumption Construction, gal/day	Diesel Construction Equipment, gal/day	Daily HHD Consumption Operational gal/day	Non-Biogas Emergency Engines, gal/day	Biogas Emergency Engines, gal/day	Daily Consumption, gal/day
2008	24.0	267	9.0	0	0	300
2009	20.0	279	6.0	65	0	370
2010	28.0	373	53.6	760	0	1,214
2011	236	1,761	111	1,111	0	3,218
2012	200	1,249	154	1,111	0	2,714
2014	0.0	0	281	1,111	202	1,593
Max	236	1,761	281	1,111	202	3,218

HHDT = Heavy – heavy- duty truck

In response to the Landfill Gas to Energy Coalition's concerns PAR 1110.2, staff has incorporated as part PAR 1110.2 a requirement to perform a technology assessment July 1, 2010 to evaluate the availability of cost effective compliance options for operators of ICEs at landfill gas and digester gas facilities. The technology assessment would evaluate whether available control technologies in 2010 would reduce NOx, VOC, and CO emissions to the concentration limits in PAR 1110.2 by July 1, 2012. If the assessment shows a potential for replacing ICEs with continuous flaring or that cost-effective control technology is not available for biogas engines, staff will return to the Governing Board with a proposal to address any new significant adverse impacts.

PAR 1110.2 includes an alternative compliance limit in subparagraph (d)(1)(B) for operators of engines that operate on 90 percent or more of landfill or digester gas effective July 1, 2012. Further, at the request of the affected industry, staff has added a provision allowing operators of engines to operate on less than 90 percent landfill or digester gas if the only alternative would be shutting down and flaring the landfill or digester gas. This concentration limits for engines burning 90 percent or more landfill or digester gas is also subject to the technology review provision that has been added to PAR 1110.2. Based on these new provisions added to PAR 1110.2 additional flaring beyond existing conditions is not anticipated as a result of implementing PAR 1110.2.

Renewable Electricity and Fuel

In-state electricity from biomass represents almost two percent of the total electricity capacity in California. Of this two percent, approximately 33 percent, or 0.66 percent, of electricity produced from biomass is produced from the combustion of landfill and biogas. In Executive Order S-06-06 Governor Schwarzenegger targeted the state to meet a 20 percent target for biomass within the established state goals for renewable generation by 2010, that is, electricity from biomass should contribute 20 percent of the state's goal for 20 percent renewable electricity. Senate Bill 1078 (SB 1078, Sher, Chapter 516, Statutes of 2002) established the California Renewables Portfolio Standard (RPS) program, which requires an annual increase in renewable generation by the utilities equivalent to at least one percent of sales, with an aggregate goal of 20 percent by 2017. The PUC accelerated the goal, requiring the utilities to obtain 20 percent of their power from renewable sources by 2010 (Senate Bill 107 codified this goal in state law).

The CEC states that statewide, 305 MW are available from landfill gas operations and 68 MW from digester gas operations in California. Based on 974 MW of total biomass electrical capacity in the state, landfill gas operations could provide 31 percent of the total potential biomass electrical capacity and digester operations could provide seven percent of the total potential biomass electrical capacity.[27] The total potential biomass electrical capacity is the amount of electricity available from all existing and future biomass sources. The term "potential" is used because not all of the sources may be converted to electricity producing sources. As part of the potential feedstock energy in biomass for California in 2006, wastewater was two percent and landfill gas was eleven percent of the 507 trillion Btu per year.

Since a goal of the technology analysis under PAR 1110.2 would be to prevent flaring of natural gas and SCAQMD staff believes that facilities operators will either use add-on control or replace ICEs with alternative technologies that would either generate electricity or LNG; there would be only adverse impacts from efficiency losses between the existing ICEs and the ICEs with add-on control or ICE replacement technologies. If the assessment shows a potential for replacing ICEs with continuous flaring or that cost-effective control technology is not available for biogas engines, staff will return to the Governing Board with a proposal to address any new significant adverse impacts. The efficiency losses are reported in Table 4-47. The largest renewable energy electrical loss because of differences in efficiency would be 101,013 MW-hours per year for the microturbine compliance option.

Southern California Edison reports that electricity from biomass and waste is projected to be two percent in 2007, which is equivalent to the actual power mix in 2006. LADWP projects electricity from biomass and waste to be one percent in 2007. The state power mix from biomass and waste was less than one percent in 2005.

There may be adverse energy impacts from an individual government program, but any energy losses caused by PAR 1110.2 other than from efficiency losses from one program (e.g., RPS electricity) would be made up in another program (e.g., biofuel). The RPS program focuses only electricity sold on the power grid. The program also allows up to 25 percent of natural gas to be reported as renewable biogas. For example, a facility operator might use 25 percent natural gas, and all of the electricity generate from the 25 percent natural gas might be sold to the power grid. If the facility operator then reduces the amount of natural gas to 10 percent, then the facility might report to the state that there was a reduction of renewable electricity equivalent to the 15 percent natural gas (25 percent – 10 percent). In reality, no renewable biogas electricity has been loss, only the electricity loss

[27] Table 2.1, CEC, A Preliminary Roadmap for the Development of Biomass in California, CEC-500-2006-095-D, December 2006.

from natural gas that was allowed to be reported as natural gas was loss. In addition, SCAQMD staff expects that facilities that use more than 10 percent natural gas would resume using the same amount used pre-PAR 1110.2 after 2012 when the concentration requirements for both the non-biogas and biogas become the same.

Another example of this would be if a biogas facility operator replaces an existing ICE with a LNG plant. The facility operator might report to under the state RPS program that after the replacement that the facility no longer produces electricity from biogas. However, while the facility operator would not generate electricity, the facility operator would ~~be~~ generate LNG to be used in replacement of gasoline or diesel.

New Exceptions and Increases in VOC and CO Emission Limits in New Engines

The new exceptions would allow the existing use of natural gas during emergencies and certain weather conditions. The new exemptions are not expected to affect the use of renewable energy. Therefore, the exceptions would not decrease natural use between 2008 and 2011. The increase in VOC and CO emission limits in new engines is not expected to alter the use of renewable or natural gas. Therefore, the new exemptions and increases in VOC and CO emission limits for new engines are not expected to make new adverse renewable energy impacts.

Total Renewable Energy Affects

Therefore, based on the above analysis, PAR 1110.2 would not generate any adverse impacts for energy. PAR 1110.2 includes a technology assessment that will include the goal of preventing adverse energy impacts from becoming significant. If the assessment shows a potential for replacing ICEs with continuous flaring or that cost-effective control technology is not available for biogas engines, staff will return to the Governing Board with a proposal to address any new significant adverse impacts.

Project Specific Mitigation Measures:

PAR 1110.2 is not designed to cause facilities to stop electric generation, but to reduce NOx, CO and VOC from ICEs. However, the cost of control and monitoring technology along with other business and economic factors may spur affected facility operators to remove ICEs and install alternative technologies. SCAQMD staff will conduct a technology assessment in 2010 to prevent affected facility operators from flaring biogas rather than using it for electricity or biofuel production. By preventing continuous flaring SCAQMD staff will prevent the loss of renewable energy in both electricity and biofuel form.

Remaining Energy Impacts:

The proposed project does not have any significant adverse energy impacts. A technology assessment will be completed in 2010 to verify that feasible control options are available to comply with PAR 1110.2 to prevent replacing biogas ICEs with continuous biogas flaring. If the technology assessment shows potential for flaring or that feasible control options for biogas engines are not available, staff will return to the Governing Board with a proposal to address any new significant adverse impacts, including rule changes if needed. Therefore, there would be no significant adverse energy impacts from PAR 1110.2.

<u>Cumulative Energy Impacts</u>:
Since PAR 1110.2 would not have project specific adverse impacts to energy, it would not have cumulative impacts.

<u>Cumulative Energy Impact Mitigation</u>:
Since there are no cumulative energy impacts no mitigation is required.

Hazards and Hazardous Materials

Accidental releases of aqueous ammonia used to reduce NOx emissions in SCR control technologies were examined in the following subsections. The analysis also evaluates accidental releases of LNG in scenarios where operators choose the alternative compliance option of replacing their ICEs with biogas to LNG plants. Since operators who retrofit existing ICEs with SCRs would not produce LNG and, conversely, facility operators who replace ICEs with biogas to LNG plants would not install SCR, the adverse impacts from accidental release from these materials would not occur at the same facility.

<u>Significance Criteria</u>

Impacts associated with hazards will be considered significant if any of the following occur:

- Non-compliance with any applicable design code or regulation.
- Non-conformance to National Fire Protection Association standards.
- Non-conformance to regulations or generally accepted industry practices related to operating policy and procedures concerning the design, construction, security, leak detection, spill containment or fire protection.
- Exposure to hazardous chemicals in concentrations equal to or greater than the Emergency Response Planning Guideline (ERPG) 2 levels. ERPG-2 concentrations are the maximum airborne concentration below which it is believed nearly all individuals could be exposed for up to one hour without experiencing or developing irreversible or other serious health effects or symptoms that could impair their ability to take protective action.

<u>Aqueous Ammonia</u>

Only biogas facilities would need SCR. All non-biogas, non-RECLAIM, lean-burn ICEs meet BACT. Existing, non-biogas, RECLAIM, lean-burn ICEs are exempt from NOx requirements in Rule 1110.2 and PAR 1110.2. One compliance option for operators of biogas facilities to comply with the NOx concentration requirement of PAR 1110.2 would be to install SCR or NOxTech systems at the 28 affected biogas facilities. As stated in the NOP/IS SCAQMD policy prohibits the use of anhydrous ammonia as a component in air pollution control technologies because it is considered to be an acutely hazardous material; in the event of an accidental release, ammonia will travel passively with prevailing winds as a dense gas; and can result in exposures that substantially exceed ERPG 2 levels. To further reduce potential hazards associated with exposure to ammonia in the event of an accidental release, a condition on SCAQMD permits is typically required that limits the aqueous ammonia concentration to 19 percent. The reason SCAQMD permits typically limit the concentration of aqueous ammonia to 19 percent is the fact that, in the event of an accidental release, it does not travel as a dense gas like anhydrous ammonia; is not on any hazardous material lists, like aqueous ammonia with higher concentrations; and, is less likely to evaporate and produce concentrations that exceed the ERPG 2 level used by the SCAQMD as a significance threshold.

Ammonia gas can cause severe eye damage, pulmonary edema, inflammation and edema of the larynx and death from spasm. Inhalation can cause wheezing, shortness of breath and chest pain. Inhalation of ammonia vapor can cause burns to the respiratory tract and residual chronic bronchitis. Chronic obstructive pulmonary disease can develop as a consequence of fibrous obstruction of the small airways. Exposure to the eyes can cause tearing, inflammation, and irritation to temporary or permanent blindness.[28]

Hazards due to transport of ammonia were evaluated in the NOP/IS. The NOP/IS concluded that PAR 1110.2 did not have the potential to create significant adverse ammonia transport impacts. No comments were received disputing this conclusion, so this topic will not be discussed further.

Hazards Due to Rupture

The ERPG 2 concentration level for ammonia is 150 ppm. Exposures to concentrations equal to or exceeding this concentration will be considered significant. "Worst-case" atmospheric conditions (e.g., low winds and stable air) will be used to evaluate whether accidental release concentrations exceed the ERPG-2 and ERPG-3 levels.

Affected operators who choose to retrofit existing ICEs with SCR or NOxTech systems would likely need to install ammonia storage tanks. Based on considerations like available area, amount of ammonia needed per year, etc., SCAQMD staff assumed that the largest ammonia tank installed to comply with PAR 1110.2 would be 5,000 gallons. Due to local fire department safety regulations, storage tanks constructed at affected facilities would be surrounded by secondary containment designs (e.g., dykes, berms, etc.). These same containment facilities would be provided at truck loading racks to contain ammonia in the event of a spill during transfer of ammonia from the truck to the storage tank.

The worst-case release scenario would be a catastrophic storage tank failure. The rupture of an ammonia storage tank would release the ammonia into the secondary containment area. Ammonia would then form a liquid pool in the secondary containment area and evaporate.

A modeling analysis was performed based on EPA's RMP Guidance for worst-case estimates for toxic releases and explosions. The RMPComp model was used to calculate the size of the impact zones. The EPA endpoint for ammonia exposure is the distance from the spill that is required to reduce the concentration to 0.14 micrograms per litter, the ERPG 2 endpoint for ammonia. The RMPComp program estimates were based on 20 percent aqueous ammonia, which is slightly higher concentration than the 19 percent ammonia proposed for this project. The 20 percent concentration is built into RMPComp and was the closest concentration available for use by the model.

[28] Technical Support Document: Toxicology Clandestine Drug Labs: Methamphetamine Volume 1, Number 1, Ammonia, ttp://www.oehha.ca.gov/public_info/pdf/TSD%20Ammonia%20Meth%20Labs%2010'8'03.pdf

To provide a "worst-case" case analysis for all ammonia tank release scenarios, the following assumptions were made:

- Ammonia tank dimensions were assumed to be twice as wide as they were high;
- The ammonia tank volume was assumed to be 10 percent larger than the nominal containment volume. (For a tank with 5,000-gallon contents, the tank volume was assumed to be 5,500 gallons);
- All dike areas were assumed to have excess capacity of 20 percent more than the tank contents. (The dike capacity for 5,000-gallon contents was assumed to be 6,000 gallons);
- All dike walls were assumed to be three feet high;
- For unconfined ammonia spills, the liquid was assumed to spread to a thickness of one centimeter in all directions on a flat impervious surface;
- Rural conditions were conservatively assumed to reduce dispersion.

Based on these assumptions, RMPComp estimates that the toxic endpoint would be 0.1 mile (528 feet) from the ammonia tank. Since biogas engines typically have back-up flare systems, it is assumed that the ICEs are not placed close to the property boundaries. However, based on a survey of biogas facilities, it was found that several facilities would have biogas engines within 0.1 mile of the property line. Therefore, it is expected in the event of an accidental release of ammonia from an ammonia storage tank at affected facilities, offsite receptors could be exposed to ammonia concentrations exceed the ERPG 2 for ammonia, 150 ppm.

According to the American Institute of Chemical Engineers (AIChE) Center for Chemical Process Safety[29], the mean time to catastrophic failure for a metallic storage vessel at atmospheric pressure is 0.985 per million hours (approximately once per 112 years). For aqueous ammonia tanks used at power plants, the California Energy Commission concluded that the catastrophic failure of an aqueous ammonia storage tank is an extremely unlikely event because the probability of a complete tank failure is insignificant, and the risk of failure due to other causes such as external events and human error also is insignificant.[30] In addition, SCAQMD staff is not aware of any aqueous ammonia storage tank that has had a catastrophic failure in recent history. As a result, the likelihood of a rupture of the aqueous ammonia storage tank occurring is extremely low. In spite of this, however, hazard impacts from exposure to ERPG 2 concentrations of ammonia are considered to be significant.

Liquefied Natural Gas

Operators who choose to replace their existing ICEs with biogas to LNG plants would also need to install LNG storage tanks to store LNG until loaded into delivery trucks. Both the storage tank and the delivery trucks would have the potential for accidental release.

[29] AIChE, 1989.
[30] CEC, 1999

Hazards associated with LNG are that, under certain conditions, it may explode or catch on fire. LNG is not explosive or flammable in unconfined areas.[31] However, as it warms and expands to a gas it becomes flammable at a concentration between five and 15 percent.

LNG is comprised mostly of methane, but may contain ethane, propane and other heavier hydrocarbons. There are no known health effects from methane except for asphyxia. Asphyxia is the condition of severely depleting the oxygen supply to the body. Methane causes asphyxia by displacing oxygen in air. Asphyxiation can occur when oxygen concentrations drop below 18 percent. Oxygen is displaced to 18 percent at a concentration of 14 percent methane. Unconsciousness from central nervous system depression occurs at 30 percent methane.

Effects of oxygen deficiency are:[32]

12-16 percent	Breathing and pulse rate are increased, with slight muscular incoordination;
10-14 percent	Emotional upsets, abnormal fatigue from exertion, disturbed respiration;
6-10 percent	Nausea and vomiting, inability to move freely, collapse, possible lack of consciousness;
Below 6 percent	Convulsive movements, gasping, possible respiratory collapse and death.

It is unlikely that off-site receptors would be exposed to LNG concentrations that would generate adverse health effects, because the lower explosive limit (LEL) for methane is five percent (50,000 ppm). The LEL is the concentration at which there is enough of the given gas to ignite or explode.

The methodology used for estimating the potential risk from a vapor explosion is that developed for off-site consequence analysis for the Risk Management Program (RMP) under 40CFR68 (EPA, 1999). For an RMP off-site consequence analysis, a gaseous release is assumed to produce a vapor explosion that results in a blast impact. For a vapor explosion, the significance level is a pressure wave (blast) of one pound per square inch (psi) and the metric examined is the modeled distance to the significant overpressure level.

<u>Hazards Due to Transport</u>

The transport of LNG is regulated by the US Department of Transportation. LNG trucks are double-walled aluminum and are designed to withstand accidents during the transport of LNG. The following description of LNG transportation and consequences is taken from the Federal Motor Carrier Safety Administration (FMCSA).[33]

[31] Federal Energy Regulatory Commission, http://www.ferc.gov/o12faqpro/default.asp?Action=Q&ID=470

[32] Canadian Centre for Occupational Health and Safety, http://www.ccohs.ca/oshanswers/chemicals/chem_profiles/methane/health_met.html

[33] Federal Motor Carrier Safety Administration, Comparative Risks of Hazardous Materials and Non-Hazardous Materials Truck Shipment Accidents/Incidents, Final Report, March 2001, www.fmcsa.dot.gov/documents/hazmatriskfinalreport.pdf.

LNG is loaded into delivery tanks at atmospheric pressure, which would be at its boiling point of -260ºF (-162ºC). The LNG is maintained at this temperature by evaporation of the boiling LNG and venting of the evaporated LNG. Because the vent is closed during shipment, the pressure in the tank builds and the temperature of the LNG increases. The FMCSA analyzed releases from delivery tanks with an average pressure of 30 psig, which would be -230ºF (-146ºC). At 30 psig, approximately 30 percent of the LNG will flash into vapor when released.

There are four scenarios that can have major consequences:

1. Release of LNG into a pool that evaporates and disperses without ignition. Approximately 40 percent of the liquefied LNG immediately flashes into vapor. The temperature of the liquid pool would be -44 ºF (-42ºC) and would therefore damage exposed vegetation and people.
2. A flammable cloud is formed that contacts an ignition source. The flame front can flash back and set the liquid pool on fire. Quantities of LNG shipped by truck would not typically cause vapor cloud explosions.
3. A boiling liquid expanding vapor explosion (BLEVE) occurs. BLEVEs would occur when an LNG tank is exposed to fire and the increase in pressure within the tank exceeds the capacity of the relief valve.
4. The tank ruptures, rockets away and ignites.

RMPComp was used for the consequence analysis for these four scenarios. The adverse impacts from the four scenarios are:

1. The area of the pool was estimated by assuming a depth of one centimeter as described in Example 29 in the EPA's Risk Management Program Guidance for Offsite Consequence Analysis.[34] A 6,000 gallon LNG pool would be 24,448 square feet. This distance would be a "worst-case" since as the LNG pool expands from the tank it will warm and evaporate.
2. A pool fire of 6,000 gallons that is released in one minute would result in a heat radiation endpoint (five kilowatts/square meter) of 0.2 mile. If a vapor cloud fire occurs, the estimated distance to the lower flammability limit would be 0.3 mile.
3. Based on 10,000 gallons the BLEVE would result in a fireball that may cause second-degree burns out to 0.3 mile.
4. The "worst-case" release estimate for 10,000 gallons in RMP*Comp is 0.3 mile from the vapor cloud explosion. Since, it is unclear as to how far away the tank would travel, it was assumed that the adverse impact would be 0.3 mile from where the tank lands. Damage to property and persons may occur from physical impact from the rocketing tank.

Because sensitive receptors may be within the endpoints above, PAR 1110.2 would be significant for hazards from accidental release of LNG during transport.

[34] EPA, Risk Management Program Guidance for Offsite Consequence Analysis, EPA 550-B-99-009, April 1989.

Hazards Due to Rupture

A "worst-case" analysis was completed for a typical LNG storage tank. Based on the landfill gas reported in the facilities survey, and based on design of the LNG facility at the Bowerman Landfill[35], the largest LNG tank would be 71,000 gallons. All LNG tanks were assumed to have a berm that holds ten percent more LNG than the storage tanks. RMP*Comp estimates the overpressure from a catastrophic release of 71,000 gallons of LNG with a berm to be 0.2 mile. Since it was determined that several facilities have engines within 0.1 mile of the property line, PAR 1110.2 would be significant for hazards from accidental release of LNG from a storage tank.

Ammonia/LNG Hazards to Schools

SCAQMD staff has geocoded biogas facilities. No biogas facilities are within one-quarter mile of a school. Based on the analysis in the "Air Quality" Section, PAR 1110.2 would reduce NOx, CO, and VOC emissions from ICEs. However, ICEs at biogas facilities that are retrofitted with SCR could generate ammonia emissions. Biogas LNG plants may have the potential to affect schools in the event of an explosion.

RMPComp was used to estimate the distance a pressure wave (blast) of one pound per square inch (psi) or the toxic end point of aqueous ammonia at these facilities would be less than the distance between the affected facilities and the schools. None of the facilities generated a toxic endpoint for ammonia or pressure wave of one psi that would reach a near-by school. Therefore, it is not expected that PAR 1110.2 would result in a safety hazard to local schools since the distance to the one psi pressure wave or toxic endpoint from affected biogas facilities is shorter than the distance from the facilities to the schools. Table 4-52 presents the facility distances to the schools and the distance to the toxic endpoint.

Table 4-57
Hazard Impacts from Affected Biogas Facilities to the Nearest Schools

Name of School	Distance to School (mile)	Distance to Toxic Endpoint (mile)	Significant for NH3	Distance to 1 psi over-pressure, (mile)	Significant for LNG
St. Edward the Confessor Parish	0.39	0.01	No	0.05	No
Capo Beach Calvary Schools	0.41	0.01	No	0.05	No
El Potrero Elementary	0.36	0.01	No	0.08	No

Hazards near Airstrips or Airports

Nine affected biogas facilities are within two miles of the following airports: Burbank, Chino Airport, Ontario International, Rialto Municipal, Riverside Municipal, San

[35] Prometheus Energy Company, Bowerman I Natural Gas Process Facility Project Description, prepared for SCAQMD, undated. The LNG storage tank proposed for the project would hold five days worth of LNG generated by the LNG facility.

Bernardino International, and Whiteman in Los Angeles County. These facilities are presented in Table 4-58.

An analysis similar to the one performed for schools was performed for airports within two miles of affected facilities. The results of the analysis indicate that no public airports or public use airports were found within the 0.1 miles (528 feet) toxic endpoint from a proposed ammonia tank. Similarly, a “worst-case” analysis was completed on each of these facilities based on the amount of LNG estimated from the landfill gas generated at the facility, then scaling the tank size from the estimated LNG generated by using the LNG facility Bowerman as a reference. RMPComp estimates the distance a pressure wave (blast) of one pound per square inch (psi) at these facilities would be less than the distance between the affected facilities and the airports. The greatest distance estimated was 0.2 miles. Therefore, although there are nine facilities within two miles of an airport or private airstrip, it is not expected that PAR 1110.2 would result in a safety hazard for the people residing or working in the project area.

Hazards to Other Non-Residential Sensitive Receptors

SCAQMD staff identified one non-residential sensitive receptor within one-quarter mile of an affected biogas facility (see Table 4-62). The toxic endpoint and overpressure of one psi overpressure are both less than the distance between the non-residential sensitive receptor and the affected biogas facility. Therefore, none of the affected biogas facilities are expected to adversely affect sensitive receptors from an accidental storage tank release.

Table 4-58
Affected Biogas Facilities within Two Miles of an Airport/Air Strip

Airports	Distance to Airport (mile)	Distance to Toxic Endpoint (mile)	Significant for NH3	Distance to 1 psi over-pressure, (mile)	Significant for LNG
Riverside Municipal	0.51	0.01	No	0.06	No
Ontario International	0.92	0.01	No	0.08	No
San Bernardino International	0.52	0.01	No	0.09	No
Whiteman, LA County	1.45	0.01	No	0.2	No
Rialto Municipal	0.49	0.01	No	0.08	No
Ontario International	1.58	0.01	No	0.08	No
Chino Airport	0.32	0.01	No	0.04	No
Burbank	1.18	0.01	No	0.1	No
Whiteman, LA County	1.97	0.01	No	0.1	No

Table 4-59
Facilities near Non-Residential Sensitive Receptors

Airports	Distance to Receptor (mile)	Distance to Toxic Endpoint (mile)	Significant for NH3	Distance to 1 psi over-pressure, (mile)	Significant for LNG
Childtime Children's Ctr	0.31	0.01	No	0.06	No

Conclusion

Delivery of ammonia was determined not to be significant in the NOP. In the above analysis catastrophic release from ammonia storage tanks was estimated to be above the ERPG 2 level of 150 ppm within 0.1 mile of the storage tank. Sensitive receptors are expected to be within 0.1 mile of the storage tank. Therefore PAR 1110.2 would be significant for accidental release from ammonia storage.

Based on the above analysis, the one psi overpressure from the cataclysmic destruction of the LNG storage tank is expected to extend 0.2 mile from the LNG storage tank. Sensitive receptors are expected to be within 0.1 mile of the storage tank. Therefore PAR 1110.2 would be significant for accidental release from LNG storage. During transportation of LNG, it was estimated that the adverse impacts from various releases would extend 0.3 mile. It is expected that sensitive receptors could be within 0.3 mile of roadway used by LNG trucks associated with PAR 1110.2. Therefore, PAR 1110.2 would be significant for accidental release from LNG transport.

PAR 1110.2 would be significant for accidental releases from ammonia storage, and delivery and storage of LNG.

The new exceptions and increase in VOC and CO emission limits for new engine is not expected to affect hazards or increase the use of hazardous materials. Therefore, the new exceptions and increases in VOC and CO emissions limits for new engines is not expected to make new adverse hazards/hazardous material impacts; nor substantially increase the severity of adverse hazards/hazardous material impacts that were already identified in the Draft EA.

Project Specific Mitigation Measures:

SCAQMD policy requiring the use of aqueous ammonia instead of anhydrous ammonia reduces adverse impacts from SCR units. In addition, the use of 19 percent aqueous ammonia reduces adverse impacts from SCR units. The location of the SCR unit is limited by the location of the ICEs and related systems.

Secondary containment (e.g. berms), valves that fail shut, emergency release values and barriers around ammonia or LNG storage tanks are design measures that are used to prevent the physical damage to storage tanks or limit the release of aqueous ammonia or LNG from storage tanks are typically required by local fire departments. Integrity testing of aqueous ammonia and LNG storage tanks assists in preventing failure from structural problems.

Further, as part of the proposed project, SCAQMD staff will require that affected facilities construct a containment system to be used during off-loading operations.

However, no additional mitigation measures were identified that would reduce the hazard and hazardous material impacts from ammonia or LNG to less than significant. Therefore, the remaining hazardous and hazardous material impacts from exposure to the ERPG 2 level of 150 ppm for ammonia and the one psi overpressure from the cataclysmic destruction of the LNG storage tank are considered to be significant.

Four accidental release scenarios were identified for the transport of LNG: release of LNG into a pool that evaporates and disperses without ignition; the ignition of a flammable cloud, a boiling liquid expanding vapor explosion (BLEVE) occurs, or the tank ruptures, rockets away and ignites. The worst-case endpoint from these scenarios is 0.3 miles from a vapor cloud fire, BLEVE or where rocketing tank would land. Assuming that these accidents would occur near receptors, PAR 1110.2 is significant for LNG accidental release during transport.

Remaining Hazards and Hazardous Materials Impacts:
Since no additional mitigation measures were identified that would reduce the hazard and hazardous material impacts from ammonia or LNG to less than significant, the remaining hazards and hazard material impacts remain significant.

Cumulative Hazards and Hazardous Materials Impacts:
As noted in previous subsections, the accidental release of aqueous ammonia during transport is not expected to result in exposures to ammonia exceeding the ERPG 2 level, 150 ppm that would be considered significant. Because receptors could be closer than 0.1 miles, an accidental release of ammonia onsite, either during unloading from a truck or an accidental release in the event of storage tank failure is considered significant. No mitigation measures were identified that could reduce project-specific releases of LNG offsite to less than significant.

Adverse impacts from an accidental release of aqueous ammonia and/or LNG are localized impacts (i.e., the impacts are isolated to the area around the facilities). None of the affected biogas facilities under PAR 1110.2 are located within one mile of each other. All aqueous ammonia toxic endpoints are equal or less than 0.1 mile and the distance of a pressure wave from an LNG release of one psi is less than or equal to 0.3 mile. Since none of the facilities are within one mile of each other, no receptors would be affected by accidents at multiple facilities. However, to the extent that affected biogas facilities are located near other facilities that have hazardous materials risks, the cumulative adverse hazard impacts from this project could contribute to existing nearby hazard risks from other projects. Therefore, cumulative hazard risks from implementing PAR 1110.2 are considered to be significant.

Cumulative Hazards and Hazardous Materials Impact Mitigation:
No additional mitigation measures were identified that reduce cumulative impacts from hazards and hazardous materials, to less than significant. Therefore, cumulative hazards/hazardous materials impacts remain significant.

Solid/Hazardous Waste

The proposed project may cause a one time increase in the quantity of waste generated at affected facilities if operators replace existing ICEs with new ICEs, catalysts, or catalyst to comply with PAR 1110.2 or replace existing ICEs with alternative control technologies. Installs of new or expanding old catalytic units (oxidation catalyst, three-way catalyst or SCR) could generate a new or increased spent catalyst waste stream.

Significance Criteria

The proposed project impacts on solid/hazardous waste will be considered significant if the following occurs:

- The generation and disposal of hazardous and non-hazardous waste exceeds the capacity of designated landfills.

Solid Waste – Replacement of Existing ICEs

Solid or hazardous wastes generated from construction-related activities would consist primarily of materials from the demolition of existing air pollution control equipment and construction associated with new air pollution control equipment. Construction-related waste would likely be disposed of at a Class II (industrial) or Class III (municipal) landfill. There are 48 Class II/Class III landfills within the SCAQMD's jurisdiction. Based on a search of the California Integrated Waste Management Board's Solid Waste Information System (SWIS) on May 16, 2007, there landfills that accept construction waste in Los Angeles, Orange, Riverside and San Bernardino counties have a combined remaining disposal capacity of approximately 750,846,000 cubic yards (1,250,367,507 tons).

As noted in previous sections in this chapter, SCAQMD staff estimates that, when compared to the cost of complying with PAR 1110.2; operators of approximately 225 non-biogas engines may elect to replace existing non-biogas engines with electric motors because this is expected to be a less costly compliance option. Further, operators of biogas facilities may replace ICEs with alternative ICE technologies, such as fuel cells, boilers, gas turbine, microturbines or LFG to LNG plants rather than comply with PAR 1110.2. As a worst-case scenario all biogas engines and 225 non-biogas engine may be removed by facility operators and replaced with alternative compliance options or electric motors, respectively. Under this scenario, up to 291 ICEs (225 non-biogas engines + 66 biogas engines) would be removed and replaced. Assuming that replacing an average engine would generate seven tons of waste, approximately 2,037 tons of waste could be generated from replacing 291 engines. The 2,037 tons of solid waste would be less than one percent (1.6×10^{-4} percent) of the remaining capacity limit, if it is conservatively assumed that one cubic yard of solid waste weighs one ton.

Solid waste that is 0.00016 percent of the total landfill disposal capacity of the district is well within the disposal capacity of district landfills. Further, even assuming that all 291 engines are removed, some engines may have relatively long useful lives remaining and would likely be resold outside of the district. Those engines not resold outside of the district contain a large percentage of useful metals and, therefore, would more likely be dismantled and sold as scrap metal. Consequently, the actual amount of material disposed of in local district landfills would be substantially less than estimated here. As a result, solid waste impacts from removing and disposing of existing engines to comply with PAR 1110.2 are not anticipated to be significant.

Solid/Hazardous Waste – Catalyst

PAR 1110.2 could generate potentially significant hazardous wastes from replacing spent catalyst generated by new or modified oxidation and SCR units. PAR 1110.2 would generate a one time disposal of catalyst from existing three-way catalyst that need to be replaced to comply with PAR 1110.2. The proposed project would eventually generate a continuous stream of hazardous waste materials from upgraded or new catalyst units. Catalysts, either oxidation catalyst, three-way catalyst or SCR, can last up to five years depending on actual operating conditions. To provide a conservative analysis, SCAQMD staff assumed that oxidation catalyst, three-way catalyst and SCR catalysts would be replaced every three years.

Operators of facilities where affected large engines have existing catalyst-based control equipment, may regenerate, reclaim or recycle the catalysts, in lieu of disposal. In the past, due to the heavy metal content and its relatively high cost, recycling oxidation catalysts has been a lucrative choice. In some cases operators of equipment retrofitted with SCR catalysts have contractual agreements with the catalyst manufacturer to reclaim and recycle the catalysts upon replacement. Although in some situations it is expected that spent catalysts could be reclaimed and recycled, it is possible that spent catalysts could be disposed of. The composition of the catalyst will determine in which type of landfill a catalyst would be disposed. There are two main types of catalysts: one in which the catalyst is coated onto a metal structure and a ceramic-based catalyst onto which the catalyst components are calcified.

Catalysts with a metal structure would not normally be considered a hazardous waste. Instead, it would be considered a metal waste, like copper pipes, and, therefore, would not be a regulated waste requiring disposal in a Class I landfill unless it is friable or brittle. Ceramic-based catalysts are not considered friable or brittle because they typically include a fiber binding material in the catalyst material. Furthermore, typical catalyst materials are not considered to be water soluble. As a result, and depending on the actual catalyst material, spent catalyst would not require disposal in a Class I landfill.

Based on the above information, it is likely that spent catalysts would be considered a “designated waste,” which is characterized as a non-hazardous waste consisting of, or containing pollutants that, under ambient environmental conditions, could be released at concentrations in excess of applicable water objectives, or which could cause degradation of the waters of the state (CCR, Title 23, Chapter 3 Subparagraph 2522(a)(1)). Depending on its actual waste designation, spent catalysts could be disposed of in a Class II landfill or a Class III landfill that is fitted with liners.

PAR 1110.2 is expected to generate 95.7 tons of catalysts over three years (14.3 tons for upgraded systems, 45.3 tons for new three way catalysts, and 36.1 tons for SCR systems) (details of the analysis can be found Appendix C), which would be slightly more than 31 tons per year based on replacing catalysts every three years.

There are 48 Class II/Class III landfills within the SCAQMD's jurisdiction. Based on a search of the California Integrated Waste Management Board's Solid Waste Information System (SWIS) on May 16, 2007, there landfills that accept construction waste in Los Angeles, Orange, Riverside and San Bernardino counties have a combined remaining disposal capacity of approximately 750,846,000 cubic yards (1,250,367,507 tons). The estimated life of the district landfills range from one year (Bradley Landfill in Los Angeles County) to 60 years (Prima Deschecha in Orange County). The total daily permitted disposal capacity of district landfills is approximately 93,979 tons per day[36]. If all 36.1 tons of catalyst material generated each year were disposed of on the same day, the catalyst material would represent 0.03 percent of the total district permitted disposal capacity. Solid waste that is 0.03 percent of the total daily permitted landfill disposal capacity for landfills in the district is well within the disposal capacity of district landfills.

However, if the oxidation catalyst, three-way catalyst and SCR catalyst are designated Class I waste, then it is expected that the catalysts would be disposed in one of three Class I landfills in California: Chemical Waste Management Kettleman Hills in Kettleman City, CA; Clean Harbors Buttonwillow in Buttonwillow, CA or Clean Harbors Westmorland in Westemorland, CA. Chemical Waste Management Kettleman Hills has a remaining capacity of 7,360,000 cubic yards with an estimated closure date of 2037. Clean Harbors Buttonwillow and Westmorland have a combined remaining capacity of 12,731,000 cubic yards with an estimated closure date of 2036. Based on the closure dates the three facilities would receive approximately 708,472 cubic yards of hazardous waste per year. Thirty-six tons per year would be less than one percent (0.004 percent) of the average hazardous waste that would be received based on the closure dates and remaining capacity. Based on these results, if catalysts were classified as a hazardous waste, there is sufficient disposal capacity in California to accommodate this amount of waste.

Therefore, whether the catalysts are disposed of as solid or hazardous waste the adverse impacts would be less than significant. The above analysis represents a "worst-case" analysis because some catalysts may be recovered and recycled, either for reuse as a catalyst or for other uses. For example, some ceramic-based SCR catalysts can be crushed and used in cement for construction projects. Further, depending on actual operating conditions at affected facilities, catalysts would not need to be replaced every three, but could last as long as five years. Based upon these considerations, significant adverse solid/hazardous waste impacts are not expected from the implementation of the proposed project.

Project Specific Mitigation Measures:

Since no significant adverse impacts were identified, no project-specific mitigation measures are required.

[36] SCAQMD. 2007. Final Program Environmental Impact Report for the 2007 Air Quality Management Plan. (SCH. No.2006111064).

Remaining Solid/Hazardous Waste Impacts:

Since no significant adverse impacts were identified, there are not remaining solid/hazardous waste impacts.

Cumulative Solid/Hazardous Waste Impacts:

Since no significant adverse project-specific solid/hazardous waste impacts were identified, these impacts are not considered to be cumulatively considerable as defined in CEQA Guidelines §14064(h)(1). As a result, no cumulative solid/hazardous waste impacts are expected from implementing PAR 1110.2.

Cumulative Solid/Hazardous Waste Impact Mitigation:

Since no significant adverse cumulative solid/hazardous waste impacts were identified, no cumulative mitigation measures are required.

POTENTIAL ENVIRONMENTAL IMPACTS FOUND NOT TO BE SIGNIFICANT

While all the environmental topics required to be analyzed under CEQA were reviewed to determine if the proposed amended rule would create significant impacts, the screening analysis concluded that the following environmental areas would not be significantly adversely affected by PAR 1110.2: agriculture resources, biological resources, cultural resources, geology/soils, hydrology and water quality, land use and planning, mineral resources, noise, population and housing, public services, recreation, and transportation/traffic. These topics were not analyzed in further detail in this environmental assessment, however, a brief discussion of each is provided below.

Agriculture Resources

Implementation of PAR 1110.2 would not result in any new construction of buildings or other structures that would convert farmland to non-agricultural use or conflict with zoning for agricultural use or a Williamson Act contract. There are no provisions in the proposed amended rule that would affect land use plans, policies, or regulations. Land use and other planning considerations are determined by local governments and no land use or planning requirements will be altered by the proposed project. Therefore no significant impacts to agricultural resources are expected.

Exceptions added to PAR 1110.2 since the release of the Draft EA would allow affected engines to operate at existing levels during emergencies and certain weather conditions; therefore, would not cause new development. Since the exemptions would only effect operations within the boundaries of existing facilities, they would not affect agricultural resources. The increase in VOC and CO emission limits for new engines is not expected cause new development. The installation and operation of new PAR 1110.2 compliant engines is expected to be similar to the installation and operation of new Rule 1110.2 engines with BACT. Therefore, the new exceptions and increase in VOC and CO emission limits for new engines are not expected to make adverse agricultural impacts significant.

Biological Resources

PAR 1110.2 would only apply to equipment or processes located within the confines of commercial or industrial facilities in commercial or industrial areas, which have already been greatly disturbed. In general, these areas currently do not support riparian habitat, federally protected wetlands, or migratory corridors. Additionally, special status plants, animals, or natural communities are not expected to be found within close proximity to the affected facilities. Therefore, the proposed project would have no direct or indirect impacts that could adversely affect plant or animal species or the habitats on which they rely in the SCAQMD's jurisdiction. Further, a conclusion of the 2003 AQMP EIR was that population growth in the region would have greater adverse effects on plant species and wildlife dispersal or migration corridors in the basin than SCAQMD regulatory activities (e.g., air quality control measures or regulations). The current and expected future land use development to accommodate population growth is primarily due to economic considerations or local government planning decisions.

There are no provisions in the proposed amended rule that would affect land use plans, policies, or regulations. Land use and other planning considerations are determined by local governments and no land use or planning requirements will be altered by the proposed project. PAR 1110.2 would not affect in any way habitat conservation or natural community conservation plans, agricultural resources or operations, and would not create divisions in any existing communities. Therefore, no significant impacts to biological resources are expected.

Exceptions added to PAR 1110.2 since the release of the Draft EA would allow affected engines to operate at existing levels during emergencies and certain weather conditions; therefore, would not cause new development. Since the exemptions would only effect operations within the boundaries of existing facilities, they would not affect biological resources. The increase in VOC and CO emission limits for new engines is not expected cause new development. The installation and operation of new PAR 1110.2 compliant engines is expected to be similar to the installation and operation of new Rule 1110.2 engines with BACT. Therefore, the new exceptions and increase in VOC and CO emission limits for new engines are not expected to make adverse biological impacts significant.

Cultural Resources

There are existing laws in place that are designed to protect and mitigate potential impacts to cultural resources. PAR 1110.2 is not expected to result in heavy earthmoving construction or operations, no impacts to historical resources will occur as a result of this project. Consequently, the proposed project has little or no potential to disturb cultural resources. Therefore, PAR 1110.2 has no potential to cause a substantial adverse change to a historical or archaeological resource, directly or indirectly destroy a unique paleontological resource or site or unique geologic feature, or disturb any human remains, including those interred outside a formal cemeteries. Further, PAR 1110.2 is not anticipated to result in any activities or promote any programs that could have a significant adverse impact on cultural resources in the district. Therefore, no significant impacts to cultural resources are expected.

Exceptions added to PAR 1110.2 since the release of the Draft EA would allow affected engines to operate at existing levels during emergencies and certain weather conditions; therefore, would not cause new development. Since the exemptions would only effect operations within the boundaries of existing facilities, they would not affect cultural resources. The increase in VOC and CO emission limits for new engines is not expected cause new development. The installation and operation of new PAR 1110.2 compliant engines is expected to be similar to the installation and operation of new Rule 1110.2 engines with BACT. Therefore, the new exceptions and increase in VOC and CO emission limits for new engines are not expected to make adverse cultural impacts significant.

Geology and Soils

The proposed project is not expected to require heavy earthmoving. Construction may be required for retrofit, replacement or new equipment. Biogas facilities may replace ICEs with turbines, microturbines, boilers or biogas to LNG facilities. The most construction occur if ICEs where replaced with LNG facilities. SCAQMD staff has had discussions with Apollo energy, which installed and operates the biogas to LNG plant at Bowerman. The biogas-to-LNG facilities are modular and dropped into place at biogas facilities. The LNG facilities are built to be modular to allow for operations to be scaled down and removed in the future. Therefore, heavy construction is not expected. Any construction is expected to follow the Uniform Building Code, which includes geological and soil safety provisions. Thus, the proposed project would not induce or alter the exposure of people or property to geological hazards such as expansive soils, lateral spreading, subsidence, liquefaction or collapse, earthquakes, landslides, mudslides, ground failure, or other natural hazards. As a result, substantial exposure of people or structures to the risk of loss, injury, or death is not anticipated. Therefore, no significant impacts to geology and soils are expected.

Exceptions added to PAR 1110.2 since the release of the Draft EA would allow affected engines to operate at existing levels during emergencies and certain weather conditions; therefore, would not cause new development. Since the exemptions would only effect operations within the boundaries of existing facilities, they would not affect geology and soils. The increase in VOC and CO emission limits for new engines is not expected cause new development. The installation and operation of new PAR 1110.2 compliant engines is expected to be similar to the installation and operation of new Rule 1110.2 engines with BACT. Therefore, the new exceptions and increase in VOC and CO emission limits for new engines are not expected to make adverse geology and soils impacts significant.

Hydrology and Water Quality

PAR 1110.2 may require the replacement or retrofit of ICE systems. PAR 1110.2 has no provision that would require the use of water or the disposal of wastewater.

Subsequent to the release of the NOP/IS, SCAQMD staff has determined the biogas operators may replace their ICEs with turbines, microturbines, boilers or biogas to LNG facilities. Based on the industry survey, biogas facilities currently remove water from biogas operations. Systems that replace ICEs would still need to remove water. SCAQMD staff expects that biogas operations would remove water in same fashion as it is removed now. For biogas facilities currently managing stormwater, PAR 1110.2 is not expected to alter the existing stormwater practices. Therefore, PAR 1110.2 is expected to be less than significant for hydrology and water quality.

Exceptions added to PAR 1110.2 since the release of the Draft EA would allow affected engines to operate at existing levels during emergencies and certain weather conditions; therefore, is not expected to use or discharge water. The increase in VOC and CO emission limits for new engines is not expected to use or discharge water. Therefore, the new exceptions and increase in VOC and CO emission limits for new engines are not expected to make adverse hydrology and water quality impacts significant.

Land Use and Planning

There are no provisions in the proposed amended rule that would affect land use plans, policies, or regulations. Land use and other planning considerations are determined by local governments and no land use or planning requirements will be altered by further monitoring and emission reductions from ICEs. All proposed operations are expected to occur within the confines of the existing commercial and industrial facilities. Since the proposed amended rule would only affect ICE systems, PAR 1110.2 would not affect in any way habitat conservation or natural community conservation plans, agricultural resources or operations, and would not create divisions in any existing communities. No new development or alterations to existing land designations will occur as a result of the implementation of the proposed amended rule. Therefore, no significant adverse impacts affecting land uses are expected.

Exceptions added to PAR 1110.2 since the release of the Draft EA would allow affected engines to operate at existing levels during emergencies and certain weather conditions; therefore, would not cause new development. Since the exemptions would only effect operations within the boundaries of existing facilities, they would not affect land use and planning. The increase in VOC and CO emission limits for new engines is not expected cause new development. The installation and operation of new PAR 1110.2 compliant engines is expected to be similar to the installation and operation of new Rule 1110.2 engines with BACT. Therefore, the new exceptions and increase in VOC and CO emission limits for new engines are not expected to make adverse land use and planning impacts significant.

Mineral Resources

There are no provisions of the proposed project that would result in the loss of availability of a known mineral resource of value to the region and the residents of the state such as aggregate, coal, clay, shale, et cetera, or of a locally-important mineral resource recovery site delineated on a local general plan, specific plan or other land use plan. Therefore, no significant adverse impacts to mineral resources are expected.

Exceptions added to PAR 1110.2 since the release of the Draft EA would allow affected engines to operate at existing levels during emergencies and certain weather conditions; therefore, would not cause new development. Since the exemptions would only effect operations within the boundaries of existing facilities, they would not affect mineral resources. The increase in VOC and CO emission limits for new engines is not expected cause new development. The installation and operation of new PAR 1110.2 compliant engines is expected to be similar to the installation and operation of new Rule 1110.2 engines with BACT. Therefore, the new exceptions and increase in VOC and CO emission limits for new engines are not expected to make adverse mineral resource impacts significant.

Noise

The existing noise environment at each of the affected facilities is dominated by industrial equipment, vehicular traffic around the facilities, and trucks entering and exiting the facilities. However, since activity during high wind event is not expected to be any greater than activity during normal operation, noise from the proposed project is not expected to produce noise in excess of current operations at each of the existing facilities. It is expected that commercial and industrial facilities affected by PAR 1110.2 would continue to comply with all existing noise control laws or ordinances. Further, Occupational Safety and Health Administration (OSHA) and California-OSHA have established noise standards to protect worker health. These potential noise increases are expected to be less than significant, thus, implementing PAR 1110.2 is not expected to result in significantly adverse noise impacts.

Exceptions added to PAR 1110.2 since the release of the Draft EA would allow affected engines to operate at existing levels during emergencies and certain weather conditions; therefore, would not cause new development, no increase in noise is expected. The increase in VOC and CO emission limits for new engines is not expected cause new development. The installation and operation of new PAR 1110.2 compliant engines is expected to be similar to the installation and operation of new Rule 1110.2 engines with BACT. Therefore, the new exceptions and increase in VOC and CO emission limits for new engines are not expected to make adverse noise impacts significant.

Population and Housing

Modifications to existing ICEs would occur completely within existing industrial facilities. The proposed project is not anticipated to generate any significant effects, either direct or indirect, on the district's population or population distribution as the additional workers needed during the construction phase are expected to come from the existing labor pool in the southern California area. Further, PAR 1110.2 is not expected to require a significant number of new permanent employees at each affected facility. In the event that new employees are hired, it is expected that the number of new employees at any one facility would be small. Human population within the jurisdiction of the SCAQMD is anticipated to grow regardless of implementing PAR 1110.2. Accordingly, no significant adverse impacts on human population or housing are expected.

Exceptions added to PAR 1110.2 since the release of the Draft EA would allow affected engines to operate at existing levels during emergencies and certain weather conditions; therefore, would not cause new development. Since the exemptions would only effect operations within the boundaries of existing facilities, they would not affect population and housing. The increase in VOC and CO emission limits for new engines is not expected cause new development. The installation and operation of new PAR 1110.2 compliant engines is expected to be similar to the installation and operation of new Rule 1110.2

engines with BACT. Therefore, the new exceptions and increase in VOC and CO emission limits for new engines are not expected to make adverse population and housing impacts significant.

Public Services

PAR 1110.2 is not expected to increase the need or demand for additional public services, e.g., fire departments, police departments, schools, parks, government, etc, above current levels. The proposed project is no expected to result in the need for new or physically altered government facilities in order to maintain acceptable service ratios, response times or other performance objectives.

A comment was received during the public review period that stated that facilities may electrify and install diesel back-up generators to comply with PAR 1110.2. The commenter stated that because diesel fuel is stored in limited amounts PAR 1110.2 could impact fire fighting operations. For systems, such as water utilities, it is expected that operators would ensure the delivery of water during emergencies. SCAQMD staff expects that water agencies that electrify systems would use the existing natural gas engines as emergency back-up generators. Using the existing engines as emergency back-up generators would provide for the delivery of water during emergencies. The technology assessment in 2010 would also address safety issues and ensure that essential public services are safe guarded. Therefore, significant adverse impacts to public services are not expected to be significant.

Exceptions added to PAR 1110.2 since the release of the Draft EA would allow affected engines to operate at existing levels during emergencies and certain weather conditions; therefore, would not cause new development. Since the exemptions would only effect operations within the boundaries of existing facilities, they would not affect public resources. The increase in VOC and CO emission limits for new engines is not expected cause new development. The installation and operation of new PAR 1110.2 compliant engines is expected to be similar to the installation and operation of new Rule 1110.2 engines with BACT. Therefore, the new exceptions and increase in VOC and CO emission limits for new engines are not expected to make adverse public resource impacts significant.

Recreation

As discussed under “Land Use” above, there are no provisions to the proposed project that would affect land use plans, policies, or regulations. Land use and other planning considerations are determined by local governments; no land use or planning requirements will be altered by the proposal. The proposed project would not increase the use of existing neighborhood and regional parks or other recreational facilities or include recreational facilities or require the construction or expansion of recreational facilities that might have an adverse physical effect on the environment. Therefore, impacts to recreational facilities are not expected to be significant.

Exceptions added to PAR 1110.2 since the release of the Draft EA would allow affected engines to operate at existing levels during emergencies and certain weather conditions; therefore, would not cause new development. Since the exemptions would only effect operations within the boundaries of existing facilities, they would not affect recreational resources. The increase in VOC and CO emission limits for new engines is not expected cause new development. The installation and operation of new PAR 1110.2 compliant engines is expected to be similar to the installation and operation of new Rule 1110.2 engines with BACT. Therefore, the new exceptions and increase in VOC and CO emission limits for new engines are not expected to make adverse recreational impacts significant.

Transportation/Traffic

PAR 1110.2 would generate additional construction and operational traffic. PAR 1110.2 would require the construction of additional monitoring and control equipment and infrastructure. PAR 1110.2 would require additional truck trips for source testing, spent catalyst removal, new catalyst delivery, ammonia delivery, and LNG haul trucks. A maximum of 62 truck trips per day is expected during construction at any facility. A maximum of 114 truck trips per day is expected during operation at any facility. Since facilities are scattered through out the SCAQMD and trips would be expected to be spread throughout the day, the overall adverse impact to traffic is expected to be minor. Therefore proposed project impacts from traffic are not expected to be significant.

Exceptions added to PAR 1110.2 since the release of the Draft EA would allow affected engines to operate at existing levels during emergencies and certain weather conditions; therefore, would not cause new development. Since natural gas is supplied to existing sites through pipe lines, the exceptions would not affect transportation and traffic. The increase in VOC and CO emission limits for new engines is not expected cause new development. The installation and operation of new PAR 1110.2 compliant engines is expected to be similar to the installation and operation of new Rule 1110.2 engines with BACT. Therefore, the new exceptions and increase in VOC and CO emission limits for new engines are not expected to make adverse transportation impacts significant.

SIGNIFICANT IRREVERSIBLE ENVIRONMENTAL CHANGES

CEQA Guidelines §15126(c) requires an environmental analysis to consider "any significant irreversible environmental changes which would be involved if the proposed action should be implemented." This EA identified aesthetics, air quality, energy hazards/hazardous materials and solid/hazardous waste as the environmental areas potentially adversely affected by the proposed project. The NOP/IS also identified solid/hazardous waste as significant, but after further analysis solid/hazardous waste was determined not to be significant.

Aesthetic significant adverse impacts can be considered irreversible since facility operators that install monitoring, emission control or ICE replacements are likely to operate with these systems for the lifetime of the equipment. Facility operators may replace these systems with similar systems.

Significant adverse impacts to air quality are not considered irreversible, since PAR 1110.2 is part of an AQMP, which overtime is designed to achieve attainment for criteria pollutants. Health risk from air toxics should be reduced overtime as clean, new engines replace older more polluting engine and diesel particulate control is added.

Significant adverse impacts from accidental releases of aqueous ammonia and LNG may be considered irreversible. As stated in the aesthetics discussion above, facility operators that install monitoring, emission control or ICE replacements are likely to operate with these systems for the lifetime of the equipment. Facility operators may replace these systems with similar systems. The delivery and storage of aqueous ammonia and LNG on-site would continue to have potential significant accidental release consequences.

POTENTIAL GROWTH-INDUCING IMPACTS

CEQA Guidelines §15126(d) requires an environmental analysis to consider the "growth-inducing impact of the proposed action." Implementing PAR 1110.2 would not, by itself, have any direct or indirect growth-inducing impacts on businesses in the SCAQMD's jurisdiction because it is not expected to foster economic or population growth or the construction of additional housing and primarily affects existing commercial and industrial facilities. No additional workers are expected to be need at the affected facilities.

CONSISTENCY

The Southern California Association of Governments (SCAG) and the SCAQMD have developed, with input from representatives of local government, the industry community, public health agencies, the USEPA - Region IX and CARB, guidance on how to assess consistency within the existing general development planning process in the Basin. Pursuant to the development and adoption of its Regional Comprehensive Plan Guide (RCPG), SCAG has developed an Intergovernmental Review Procedures Handbook (June 1, 1995). The SCAQMD also adopted criteria for assessing consistency with regional plans and the AQMP in its CEQA Air Quality Handbook. The following sections address the consistency between PAR 1110.2 and relevant regional plans pursuant to the SCAG Handbook and SCAQMD Handbook.

Consistency with Regional Comprehensive Plan and Guide (RCPG) Policies

The RCPG provides the primary reference for SCAG's project review activity. The RCPG serves as a regional framework for decision making for the growth and change that is anticipated during the next 20 years and beyond. The Growth Management Chapter (GMC) of the RCPG contains population, housing, and jobs forecasts, which are adopted by SCAG's Regional Council and that reflect local plans and policies, shall be used by SCAG in all phases of implementation and review. It states that the overall goals for the region are to (1) re-invigorate the region's economy, (2) avoid social and economic inequities and the geographical isolation of communities, and (3) maintain the region's quality of life. Based on the following discussion PAR 1110.2 is consistent with RCPG policies.

Consistency with Growth Management Chapter (GMC) to Improve the Regional Standard of Living

The Growth Management goals are to develop urban forms that enable individuals to spend less income on housing cost, that minimize public and private development costs, and that enable firms to be more competitive, strengthen the regional strategic goal to stimulate the regional economy. PAR 1110.2 in relation to the GMC would not interfere with the achievement of such goals, nor would it interfere with any powers exercised by local land use agencies. Modifications to existing ICEs at affected facilities would likely be subject to permit modifications. The SCAQMD has implemented a series of actions over the six to eight years to streamline the SCAQMD permit process. As a result, PAR 1110.2 would not interfere with efforts to minimize red tape and expedite the permitting process to maintain economic vitality and competitiveness.

Consistency with Growth Management Chapter (GMC) to Provide Social, Political and Cultural Equity

The Growth Management goals are to develop urban forms that avoid economic and social polarization, promotes the regional strategic goals of minimizing social and geographic disparities, and of reaching equity among all segments of society. Consistent with the Growth Management goals, local jurisdictions, employers and service agencies should provide adequate training and retraining of workers, and prepare the labor force to meet the challenges of the regional economy. Growth Management goals also include encouraging employment development in job-poor localities through support of labor force retraining programs and other economic development measures. Local jurisdictions and other service providers are responsible for developing sustainable communities and providing, equally to all members of society, accessible and effective services such as: public education, housing, health care, social services, recreational facilities, law enforcement, and fire protection. Implementing PAR 1110.2 has no effect on and, therefore, is not expected to interfere with the goals of providing social, political and cultural equity.

Consistency with Growth Management Chapter (GMC) to Improve the Regional Quality of Life

The Growth Management goals also include attaining mobility and clean air goals and developing urban forms that enhance quality of life, accommodate a diversity of life styles, preserve open space and natural resources, are aesthetically pleasing, preserve the character of communities, and enhance the regional strategic goal of maintaining the regional quality of life. The RCPG encourages planned development in locations least likely to cause environmental impacts, as well as supports the protection of vital resources such as wetlands, groundwater recharge areas, woodlands, production lands, and land containing unique and endangered plants and animals. While encouraging the implementation of measures aimed at the preservation and protection of recorded and unrecorded cultural resources and archaeological sites, the plan discourages development in areas with steep slopes, high fire, flood and seismic hazards, unless complying with special design requirements. Finally, the plan encourages mitigation measures that reduce noise in certain locations, measures aimed at preservation of biological and ecological resources, measures that would reduce exposure to seismic hazards, minimize earthquake damage, and develop emergency response and recovery plans. PAR 1110.2 would reduce NOx, CO and VOC emissions from ICEs and better monitor compliance. Therefore, in relation to the GMC, PAR 1110.2 is not expected to interfere with any air quality goals related to the GMC.

Consistency with Regional Mobility Element (RMP) and Congestion Management Plan (CMP)

PAR 1110.2 is consistent with the RMP and CMP since no significant adverse impact to transportation/circulation would result from further control of NOx, CO and VOC from

ICEs. Since PAR 1110.2 is not expected to have a significant adverse impact on transportation/traffic, PAR 1110.2 is not expected to significantly adversely affect circulation patterns or congestion management.

CHAPTER 5

ALTERNATIVES

INTRODUCTION

This ~~Draft~~Final EA provides a discussion of a range of reasonable alternatives to the proposed project as required by state CEQA Guidelines §15126.6. Alternatives include measures for attaining objectives of the proposed project and provide a means for evaluating the comparative merits of each alternative. A "No Project" alternative must also be evaluated (CEQA Guidelines §15126.6(e)). The range of alternatives must be sufficient to permit a reasoned choice, but need not include every conceivable project alternative. State CEQA Guidelines §15126.6(c) specifically notes that the range of alternatives required in a CEQA document is governed by a 'rule of reason' and only necessitates that the CEQA document set forth those alternatives necessary to permit a reasoned choice. The key issue is whether the selection and discussion of alternatives fosters informed decision making and meaningful public participation. A CEQA document need not consider an alternative whose effect cannot be reasonably ascertained and whose implementation is remote and speculative.

SCAQMD Rule 110 (the rule which implements the SCAQMD's certified regulatory program) does not impose any greater requirements for a discussion of project alternatives in an environmental assessment than is required for an EIR under CEQA.

SCAQMD's policy document Environmental Justice Program Enhancements for FY 2002-03, Enhancement II-1 recommends that all SCAQMD CEQA assessments include a feasible project alternative with the lowest air toxics emissions. In other words, for any major equipment or process type under the scope of the proposed project that creates a significant environmental impact, at least one alternative, where feasible, shall be considered from a "least harmful" perspective with regard to hazardous air emissions.

The Governing Board may choose to adopt any portion or all of any alternative presented below. The Governing Board is able to adopt any portion or all of any of the following alternatives because the impacts of each alternative are fully disclosed to the public and the public has the opportunity to comment on the alternatives and impacts generated by each alternative.

ALTERNATIVES REJECTED AS INFEASIBLE

A CEQA document should identify any alternatives that were considered by the lead agency, but were rejected as infeasible during the scoping process and explain the reasons underlying the lead agency's determination [CEQA Guidelines §15126.6(c)]. Because the scope of the current amendments is focused primarily on enhancing enforcement and obtaining further emission reductions through currently available control technologies and because there are a number options for reducing emissions from affected equipment, e.g., installing control equipment or replacing existing ICEs with alternative compliance technologies, no alternatives identified were rejected as infeasible.

DESCRIPTION OF ALTERNATIVES

The following proposed alternatives were developed by modifying specific components of the proposed amended rule. The rationale for selecting and modifying specific components of the proposed amended rule to generate feasible alternatives for the analysis is based on

CEQA's requirement to present "realistic" alternatives; that is, alternatives that can actually be implemented.

In addition to the No Project Alternative, the following three alternatives were developed by identifying and modifying major components of PR 1110.2. As stated in the Areas of Controversy section of Chapter 1, staff and stakeholders have been and are currently in discussions regarding specific provisions to be included in PAR 1110.2. Specifically, the primary components of the proposed alternatives that have been modified are the requirements related to emission concentration compliance limits for the three pollutants regulated by Rule 1110.2, efficiency correction for biogas combustion, source testing averaging times, compliance dates, natural life allowance, natural gas usage for biogas engines, and low usage exemptions. The alternatives, summarized in Table 5-1 and described in the following subsections, include the following: Alternative A (No Project); Alternative B (Low Use); and Alternative C (Enhanced Enforcement). Unless otherwise specifically noted, all other components of the project alternatives are identical to the components of PAR 1110.2. The following subsections provide a brief description of each project alternative and Table 5-1 summarizes the main components of each alternative.

Alternative A - No Project Alternative

Alternative A, the No Project Alternative, would mean not adopting PAR 1110.2 and, therefore, maintaining the existing emission compliance limits, CEMS requirements, source testing requirements, etc., of Rule 1110.2.

Alternative B – Low Use Alternative

PAR 1110.2 has an exception to concentration limits for non-biogas ICEs that are used less than 500 hours or that burn less than one billion Btu of fuel per year (high heating value). Alternative B, the Low Use Alternative, would expand the low use exception relative to complying with the proposed emission reduction requirements to non-biogas engines ICEs that are used less than 1,000 hours or that burn less than two billion Btu per year of fuel (high heating value). What this means is that the non-biogas engines that qualify for this exception would continue to comply with existing Rule 1110.2 NOx, VOC, and CO concentration requirements. This exception would apply to 32 additional engines.

The averaging time for PAR 1110.2 compliance limits is 15 minutes. Alternative B would also extend the averaging time from 15 minutes to one hour. Some affected facility operators have stated that existing control devices cannot meet the PAR 1110.2 compliance limits because of fluctuations in emissions and that a longer averaging time would prevent the need to replace existing control equipment with newer equipment for minor reductions in emissions. The averaging time component of Alternative B, therefore, responds to facility operators' comments regarding averaging times.

Table 5-1
Summary of PAR 1110.2 and Project Alternatives

Requirement	Proposed Project	Alternative A (No Project)	Alternative B (Low Use)	Alternative C (~~Compliance Only~~ Enhanced Compliance)	Alterative D (BACT)
Compliance Limits	11 ppm NOx 30 ppm VOC 250 ppm CO	NOx VOC CO (ppm) Table I: 11 30 70 Table II: 36 250 2,000 Table III ≥ 50 bhp: 36 250 NA Table III >50 bhp < 500 bhp: 45 250 NA	11 ppm NOx 30 ppm VOC 250 ppm CO	NOx VOC CO (ppm) Table I: 11 30 70 Table II: 36 250 2,000 Table III ≥ 50 bhp: 36 250 NA Table III >50 bhp < 500 bhp: 45 250 NA	11 ppm NOx 30 ppm VOC 70 ppm CO
Efficiency Correction for Biogas	No	Yes	No	No	No
Averaging Times	15 min	15 min	1 hour	15 min	15 min
Compliance Dates	Emission limits 2010 - 2012 Monitoring 2008 - 2010	N/A	Emission limits 2010 - 2012 Monitoring 2008 - 2010	Monitoring 2008 - 2010	Emission limits 2012 - 2014 Monitoring 2008 - 2010
Natural Life Allowance	None	N/A	None	None	Additional two years to comply with concentration limits
Natural Gas Percentage Limits	10	N/A	10	25	10
Low Usage Exception from Non-Biogas Compliance Limits	Less than 500 hours or less than 1,000 MMBtu annually	None	Less than 1,000 hours or less than 2,000 MMBtu annually	None	Same as PAR 1110.2

Table 5-1 (continued)
Summary of PAR 1110.2 and Project Alternatives

Requirement	**Proposed Project**	**Alternative A (No Project)**	**Alternative B (Low Use)**	**Alternative C (~~Compliance Only~~ Enhanced Compliance)**	**Alterative D (BACT)**
CEMS	Stationary ICE groups of 1,500 bhp ICEs or more included in CEMS unless < 500 bhp or operated <1,000 hr/yr or < 8 x 10^9 Btu/year	N/A	Same as PAR 11102, except lean-burn engines are exempt from CEMS requirements	Same as PAR 1110.2	Same as PAR 1110.2
Replacement of Existing ICE with Electric Motors	Voluntary	None	Voluntary	None	Mandatory

Similar to the proposed project, because Alternative B contains the same emission concentration requirements, SCAQMD staff expects that operators of the same categories of non-biogas engines would choose to replace existing engines with electric motors as a less costly compliance option.

Alternative B would include all of the CEMS requirements in the proposed project, but would add an exception that excludes lean-burn engines from the NOx CEMS requirements. It was estimated that the exception would apply to approximately nine facilities.

All other provisions of Alternative B are the same as PAR 1110.2, including compliance dates, reporting provisions, etc.

Alternative C – Enhanced Enforcement

Alternative C, the Enhanced Enforcement Alternative, would limit modifications to Rule 1110.2 to address compliance issues identified by SCAQMD inspectors. Similar to PAR 1110.2, to enhance enforcement, Alternative C would include the same: CEMs installation requirements in paragraph (e)(3); inspection and monitoring plan requirements in paragraph (e)(4); and monitoring, testing, recordkeeping, and reporting requirements; and reporting noncompliance requirements in subdivision (f). Alternative C would also eliminate the efficiency correction for biogas averaging times. No changes would be made to the existing compliance limits in Rule 1110.2. Replacement of non-biogas engines with electric motors is not expected under Alternative C.

Alternative C is considered to be the least toxic alternative for the following reasons. Although Alternative C would not generate emission reductions beyond what is currently required by Rule 1110.2, it will enhance enforcement of the rule to obtain emission reductions originally anticipated for the Rule. For example, as indicated in Chapter 3, during unannounced site visits and compliance tests, some engines were demonstrated to exceed existing emission concentrations in Rule 1110.2, some engines by a wide margin. Further, because Alternative C does not impose additional emission reduction requirements, it is not expected that add-on control would be installed, ICEs replaced with alternative technologies, or emergency engines installed. As a result, Alternative C would not result in new ammonia slip emissions or diesel exhaust particulate. Ammonia is not considered to be a carcinogen, it can have chronic and acute health impacts. Diesel particulate has both carcinogenic and chronic health affects.

Alternative D – Best Available Control Technology

Alternative D, the Best Available Control Technology (BACT) Alternative, would lower CO emission compliance limits to BACT emissions levels. The proposed emission compliance limits for NOx and VOC would be the same as for PAR 1110.2. With respect to emission compliance limits, Alternative D is similar to staff's initial proposal for PAR 1110.2, which also would have established compliance limits for CO at BACT emissions levels. Alternative D would include a useful life provision extending the final compliance dates for new concentration limits from 2012 to 2014 for biogas engines.

Alternative D would include a requirement that facility operators replace existing non-biogas engines with electric motors based on engine categories identified in Table 4-7, where it is expected that installing electric motors would be less costly than complying with the requirements of PAR 1110.2. An exception would be included that would allow facility operators to demonstrate to the Executive Officer other mitigating factors besides compliance/replacement costs that may prevent facility operators from replacing affected non-biogas engines with electric motors.

The comparison of the relative merits of the individual alternatives assumes that for Alternative D, operators of 169 non-biogas engines would install electric motors, while operators of the remaining 56 non-biogas engines would seek the exception to installing an electric motor due to unique operating conditions. It is assumed that the operators of the 56 non-biogas engine who do not install electric motors will comply with the proposed emission limits in this alternative. This assumption is consistent with the analysis of PAR 1110.2.

EVALUATION OF THE RELATIVE MERITS OF PROJECT ALTERNATIVES

Consistent with CEQA Guidelines §15126.6(a), the following subsections evaluate the relative merits of each project alternative. Potential adverse impacts for the environmental topics are quantified where sufficient data are available.

Alternative A - No Project Alternative

Aesthetics

Alternative A would not be expected to create significant adverse aesthetics impacts, because no construction or modification of process operations or procedures would be required.

Air Quality

Alternative A would not create significant adverse construction air quality impacts because no construction or modification of processes operations or procedures would be required. One of the primary reasons for amending Rule 1110.2 is to improve compliance with the emission concentrations of the rule by imposing CEMs requirements, inspection and monitoring plan requirements; monitoring, testing, recordkeeping, and reporting requirements; etc. By not amending Rule 1110.2, it is possible that a large number of affected engines would continue to operate out of compliance. As indicated in Table 5-2, engines exceeding compliance limits could do so in amounts that exceeds applicable SCAQMD significance thresholds. Therefore, it is concluded that Alternative A could create significant adverse operation air quality impacts. In addition, implementing Alternative A would not result in the CO2 emission reduction benefits anticipated for PAR 1110.2.

Table 5-2
Potential Emission Impacts in Violation of Rule 1110.2 from Implementing Alternative A

	NOx, lb/day	CO, lb/day	VOC, lb/day
Excess Emissions	9,195	54,243	2,517
Significance Thresholds	55	550	55
Significant	Yes	Yes	Yes

Energy

Alternative A would have no significant adverse diesel energy impacts, because no construction or modification of process operations or procedures would be required. Alternative A would not reduce electricity generation from existing engines that are retrofitted or replaced with less efficient energy generation equipment such as turbines, microturbines, etc., as would be the case under PAR 1110.2. Alternative A, however, would not provide the beneficial reduction in natural gas consumption that is anticipated under PAR 1110.2. Overall, Alternative A would not create any significant adverse energy impacts.

Hazards/Hazardous Materials

The analysis of potential hazard/hazardous materials impacts from implementing PAR 1110.2 in Chapter 4 concluded that the alternative compliance option of replacing existing biogas ICEs with biogas to LNG plants could produce significant adverse explosion and fire impacts to nearby receptors. Because Alternative A would impose no additional compliance requirements, it would not be expected to generate any significant adverse hazard impacts compared to PAR 1110.2.

Solid/Hazardous Waste

Chapter 4 concluded that, although there could be some solid waste impacts from disposal of ICE that are replaced with alternative compliance options and disposal of spent catalysts, local landfills and/or hazardous waste landfills in California could accommodate this increase in waste disposal. As a result, solid/hazardous waste impacts were concluded to be less than significant. Because Alternative A would impose no additional compliance requirements, it would not be expected to generate any significant adverse solid hazardous waste impacts compared to PAR 1110.2.

Alternative B – Low Use Alternative

Aesthetics

Alternative B would have similar adverse aesthetic impacts to PAR 1110.2. It is expected that Alternative B would generate fewer adverse aesthetic impacts for non-biogas facilities because the low use exception would capture fewer of these types of facilities and, as a result, operators of these facilities would not need to install control technology. However, Alternative B would have the same requirements for biogas facilities as PAR 1110.2. Since the analysis of PAR 1110.2 concluded that biogas facilities would potentially create the greatest adverse visual impacts from installing control systems (SCR, NOxTech, etc.) or ICE replacement systems (turbines, LNG plants, etc.), the worse-case adverse visual impacts for Alternative B would be equivalent to those identified for PAR 1110.2. Therefore, like PAR 1110.2, it is expected that Alternative B would generate significant adverse impacts on aesthetics.

Air Quality

Construction

Because the low use exception from further emission reduction requirements would be extended to non-biogas engines under Alternative B, it is anticipated that 11 fewer ICEs would need to be retrofitted with an oxidation catalyst and 30 few ICE would need to upgrade three-way catalyst. Alternative B would result in the installation of fewer catalysts; it is estimated to exclude eight facilities.

Alternative B would have an exception to the NOx CEMS requirements for lean-burn engines. The exception is expected to affect nine engines non-biogas at three facilities. Environmental analysis for Alternative B includes affects to direct emissions but to be conservative did not lessen secondary emissions (heavy-duty delivery trucks), hazard or solid/hazardous waste adverse impacts. The remaining facilities would be biogas facilities that would potential generate the largest construction emissions from the installation of add-on emission controls or replacement of the existing biogas engines with ICE alternative technologies (e.g., gas turbines, microturbines, LNG facilities, etc.).

Therefore these exceptions would likely have little effect on the number of construction projects on a typical day or, as a result, peak day construction emissions. Therefore, it assumed that the construction emissions for Alternative B would be approximately equivalent to those identified for PAR 1110.2.

Operational

Since Alternative B would reduce the number of non-biogas engines that would need to be retrofitted with three-way catalyst or oxidation catalysts upgrade, the emission reductions from Alternative B would be less than the proposed project. Fewer oxidation catalysts would also lead to fewer catalyst truck trips because smaller amounts of spent catalyst would be disposed of and fewer replacement catalysts would be needed.

Potential secondary air quality impacts identified for biogas engines are the same as the proposed project and include ammonia slip emissions from new SCR systems and additional truck trips for spent and replacement catalysts. ICE engines that are replaced with alternative control technologies would be expect to generate similar secondary air quality impacts to the proposed project.

The air quality effects of implementing Alternative B are presented in the same way as they were for PAR 1110.2. Tables 5-3 through 5-7 present the total emissions inventory by compliance year that takes into consideration the declining operating emissions inventory from affected equipment reducing emissions to comply with Alternative B and increased construction emissions from installing air pollution control and monitoring equipment or installing alternative compliance technologies. Table 5-3 shows the remaining emissions by compliance year and construction emissions for the compliance option of all biogas plant operators retrofitting using SCR. Table 5-4 shows the remaining emissions by compliance year and construction emissions for the compliance option of all biogas plant operators replacing ICEs with gas turbines. Table 5-5 shows the remaining emissions by compliance year and construction emissions for the compliance option of biogas operators replacing ICEs with microturbines. Table 5-6 shows the remaining emissions by compliance year and construction emissions for the compliance option of biogas operators replacing ICEs with digester plant and LNG plants at landfills. Table 5-7 shows the remaining emissions by compliance year and construction emissions for the compliance option of operators replacing ICEs with microturbines and landfill gas facility operators replacing ICEs with LNG plants.

A summary of operation emissions by biogas option are presented in Tables 5-3 through 5-7. Emission increases and emissions reductions from Alternative B are presented in Table 5-8 through 5-12.

Table 5-3
Net Criteria Emission Inventories from Non-biogas Facilities and the SCR Compliance Option for Biogas Facilities under Alternative B

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5 lb/day
2008	~~9,089~~ 9,094	~~53,909~~ 53,942	~~2,470~~ 2,479	~~543.9~~ 545	~~876.8~~ 878	~~874.7~~ 876
2009	~~6,410~~ 6,415	~~22,399~~ 22,432	~~1,790~~ 1,799	~~543~~ 544	~~858~~ 859	~~856~~ 857
2010	~~6,004~~ 6,009	~~17,385~~ 17,418	~~1,297~~ 1,306	~~534~~ 535	~~844~~ 845	~~842~~ 843
2011	~~5,595~~ 5,600	~~13,617~~ 13,650	~~1,240~~ 1,249	~~529~~ 530	~~834~~ 835	~~831~~ 832
2012	4,181	13,481	1,020	538	833	831
2014	4,188	13,477	1,018	538	833	831

Table 5-4
Net Criteria Emission Inventories from Non-biogas Facilities and the Gas Turbines Option for Biogas Facilities under Alternative B

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5 lb/day
2008	~~9,089~~ 9,094	~~53,909~~ 53,942	~~2,470~~ 2,479	~~543.9~~ 545	~~876.8~~ 878	~~874.7~~ 876
2009	~~6,410~~ 6,415	~~22,399~~ 22,432	~~1,790~~ 1,799	~~543~~ 544	~~858~~ 859	~~856~~ 857
2010	~~6,004~~ 6,009	~~17,385~~ 17,418	~~1,297~~ 1,306	~~534~~ 535	~~844~~ 845	~~842~~ 843
2011	~~5,589~~ 5,594	~~13,616~~ 13,649	~~1,239~~ 1,248	~~529~~ 530	~~833~~ 834	~~831~~ 832
2012	4,882	7,416	542	538	1,019	1,017
2014	4,888	7,412	540	538	1,019	1,017

Table 5-5
Net Criteria Emission Inventories from Non-biogas Facilities and the Microturbine Compliance Option for Biogas Facilities under Alternative B

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5 lb/day
2008	~~9,089~~ 9,094	~~53,909~~ 53,942	~~2,470~~ 2,479	~~543.9~~ 545	~~876.8~~ 878	~~874.7~~ 876
2009	~~6,410~~ 6,415	~~22,399~~ 22,432	~~1,790~~ 1,799	~~543~~ 544	~~858~~ 859	~~856~~ 857
2010	~~6,004~~ 6,009	~~17,385~~ 17,418	~~1,297~~ 1,306	~~534~~ 535	~~844~~ 845	~~842~~ 843
2011	~~5,589~~ 5,594	~~13,616~~ 13,649	~~1,239~~ 1,248	~~529~~ 530	~~833~~ 834	~~831~~ 832
2012	3,917	6,228	647	538	760	758
2014	3,923	6,224	645	538	760	758

Table 5-6
Net Criteria Emission Inventories from Non-biogas Facilities and the Gas Turbines at Digester Gas Facilities and LNG Facilities at Landfills Compliance Option for Biogas Facilities under Alternative B

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5 lb/day
2008	~~9,089~~ 9,094	~~53,909~~ 53,942	~~2,470~~ 2,479	~~543.9~~ 545	~~876.8~~ 878	~~874.7~~ 876
2009	~~6,410~~ 6,415	~~22,399~~ 22,432	~~1,790~~ 1,799	~~543~~ 544	~~858~~ 859	~~856~~ 857
2010	~~6,004~~ 6,009	~~17,385~~ 17,418	~~1,297~~ 1,306	~~534~~ 535	~~844~~ 845	~~842~~ 843
2011	~~6,076~~ 6,081	~~13,816~~ 13,849	~~1,297~~ 1,306	~~529~~ 530	~~872~~ 873	~~857~~ 858
2012	4,746	6,746	586	211	911	896
2014	4,377	6,576	535	211	878	876

Table 5-7
Net Criteria Emission Inventories from Non-biogas Facilities and the Microturbines at Digester Gas Facilities and LNG Facilities at Landfills Compliance Option for Biogas Facilities under Alternative B

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5 lb/day
2008	~~9,089~~ 9,094	~~53,909~~ 53,942	~~2,470~~ 2,479	~~543.9~~ 545	~~876.8~~ 878	~~874.7~~ 876
2009	~~6,410~~ 6,415	~~22,399~~ 22,432	~~1,790~~ 1,799	~~543~~ 544	~~858~~ 859	~~856~~ 857
2010	~~6,004~~ 6,009	~~17,385~~ 17,418	~~1,297~~ 1,306	~~534~~ 535	~~844~~ 845	~~842~~ 843
2011	~~6,076~~ 6,081	~~13,816~~ 13,849	~~1,297~~ 1,306	~~529~~ 530	~~872~~ 873	~~857~~ 858
2012	4,362	6,281	632	211	805	791
2014	3,993	6,111	581	211	773	771

Table 5-8 shows the net emissions effect (emission reduction) by compliance year, which includes construction emissions, for the compliance option of all biogas plant operators retrofitting using SCR. Table 5-9 shows the net emissions effect (emission reduction) by compliance year, which includes construction emissions, for the compliance option of all biogas plant operators replacing ICEs with gas turbines. Table 5-10 shows the net emissions effect (emission reduction) by compliance year, which includes construction emissions, for the compliance option of biogas operators replacing ICEs with microturbines. Table 5-11 shows the net emissions effect (emission reduction) by compliance year, which includes construction emissions, for the compliance option of biogas operators replacing ICEs with digester plant and LNG plants at landfills. Table 5-12 shows the net emissions effect (emission reduction) by compliance year, which includes construction emissions, for the compliance option of operators replacing ICEs with microturbines and landfill gas facility operators replacing ICEs with LNG plants.

Table 5-8
Net Criteria Emission Effects from Non-Biogas Facilities and Installing SCR at All Biogas Plants -Total Compared to Baseline under Alternative B

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5 lb/day
2008	~~(106)~~ (100)	~~(334)~~ (301)	~~(22)~~ (14)	~~(7.5)~~ (6.9)	~~(0.1)~~ 0.8	~~0.4~~ 0.4
2009	~~(3,191)~~ (3,185)	~~(36,858)~~ (36,825)	~~(1,196)~~ (1,187)	~~(17)~~ (17)	~~(33)~~ (32)	~~(33)~~ (32)
2010	~~(3,191)~~ (3,185)	~~(36,858)~~ (36,825)	~~(1,196)~~ (1,187)	~~(17)~~ (17)	~~(33)~~ (32)	~~(33)~~ (32)
2011	~~(3,600)~~ (3,594)	~~(40,626)~~ (40,593)	~~(1,253)~~ (1,244)	~~(23)~~ (22)	~~(43)~~ (42)	~~(44)~~ (43)
2012	(5,013)	(40,762)	(1,473)	(13)	(44)	(44)
2014	(5,007)	(40,766)	(1,475)	(13)	(44)	(44)

Numbers in parentheses represent emission reductions.

Table 5-9
Net Criteria Emission Effects from Non-Biogas Facilities and Gas Turbines at All Biogas Plants -Total Compared to Baseline under Alternative B

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5 lb/day
2008	~~(106)~~ (100)	~~(334)~~ (301)	~~(22)~~ (14)	~~(7.5)~~ (6.9)	~~(0.1)~~ 0.8	~~0.4~~ 0.4
2009	~~(3,191)~~ (3,185)	~~(36,858)~~ (36,825)	~~(1,196)~~ (1,187)	~~(17)~~ (17)	~~(33)~~ (32)	~~(33)~~ (32)
2010	~~(3,191)~~ (3,185)	~~(36,858)~~ (36,825)	~~(1,196)~~ (1,187)	~~(17)~~ (17)	~~(33)~~ (32)	~~(33)~~ (32)
2011	~~(3,605)~~ (3,600)	~~(40,627)~~ (40,594)	~~(1,253)~~ (1,245)	~~(23)~~ (22)	~~(43)~~ (43)	~~(44)~~ (43)
2012	(4,313)	(46,827)	(1,951)	(13)	142	142
2014	(4,307)	(46,831)	(1,953)	(13)	142	142

Numbers in parentheses represent emission reductions.

Table 5-10
Net Criteria Emission Effects from Non-Biogas Facilities and Microturbines at All Biogas Plants -Total Compared to Baseline under Alternative B

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5 lb/day
2008	~~(106)~~ (100)	~~(334)~~ (301)	~~(22)~~ (14)	~~(7.5)~~ (6.9)	~~(0.1)~~ 0.8	~~0.4~~ 0.4
2009	~~(3,191)~~ (3,185)	~~(36,858)~~ (36,825)	~~(1,196)~~ (1,187)	~~(17)~~ (17)	~~(33)~~ (32)	~~(33)~~ (32)
2010	~~(3,191)~~ (3,185)	~~(36,858)~~ (36,825)	~~(1,196)~~ (1,187)	~~(17)~~ (17)	~~(33)~~ (32)	~~(33)~~ (32)
2011	~~(3,605)~~ (3,600)	~~(40,627)~~ (40,594)	~~(1,254)~~ (1,245)	~~(23)~~ (22)	~~(43)~~ (43)	~~(44)~~ (43)
2012	(5,278)	(48,015)	(1,846)	(13)	(117)	(117)
2014	(5,272)	(48,019)	(1,848)	(13)	(117)	(117)

Numbers in parentheses represent emission reductions.

Table 5-11
Net Criteria Emission Effects from Non-Biogas Facilities and Gas Turbines at Digester Gas Facilities and LNG Facilities at Landfills -Total Compared to Baseline under Alternative B

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5 lb/day
2008	~~(106)~~ (100)	~~(334)~~ (301)	~~(22)~~ (14)	~~(7.5)~~ (6.9)	~~(0.1)~~ 0.8	~~0.4~~ 0.4
2009	~~(3,191)~~ (3,185)	~~(36,858)~~ (36,825)	~~(1,196)~~ (1,187)	~~(17)~~ (17)	~~(33)~~ (32)	~~(33)~~ (32)
2010	~~(3,191)~~ (3,185)	~~(36,858)~~ (36,825)	~~(1,196)~~ (1,187)	~~(17)~~ (17)	~~(33)~~ (32)	~~(33)~~ (32)
2011	~~(3,119)~~ (3,113)	~~(40,427)~~ (40,394)	~~(1,196)~~ (1,187)	~~(22)~~ (22)	~~(5)~~ (4)	~~(18)~~ (17)
2012	(4,449)	(47,497)	(1,907)	(340)	33.6	21.28
2014	(4,818)	(47,667)	(1,957)	(340)	1.2	0.73

Numbers in parentheses represent emission reductions.

Table 5-12
Net Criteria Emission Effects from Non-Biogas Facilities and Microturbines at Digester Gas Facilities and LNG Facilities at Landfills -Total Compared to Baseline under Alternative B

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5 lb/day
2008	~~(106)~~ (100)	~~(334)~~ (301)	~~(22)~~ (14)	~~(7.5)~~ (6.9)	~~(0.1)~~ 0.8	~~0.4~~ 0.4
2009	~~(3,191)~~ (3,185)	~~(36,858)~~ (36,825)	~~(1,196)~~ (1,187)	~~(17)~~ (17)	~~(33)~~ (32)	~~(33)~~ (32)
2010	~~(3,191)~~ (3,185)	~~(36,858)~~ (36,825)	~~(1,196)~~ (1,187)	~~(17)~~ (17)	~~(33)~~ (32)	~~(33)~~ (32)
2011	~~(3,119)~~ (3,113)	~~(40,427)~~ (40,394)	~~(1,196)~~ (1,187)	~~(22)~~ (22)	~~(5)~~ (4)	~~(18)~~ (17)
2012	(4,833)	(47,962)	(1,861)	(340)	(72)	(84)
2014	(5,202)	(48,132)	(1,912)	(340)	(104)	(104)

Numbers in parentheses represent emission reductions.

As is the case with PAR 1110.2, the worst-case emissions from Alternative B would occur if all biogas operators replace existing ICEs with gas turbines. PM2.5 emissions would exceed the PM2.5 significance threshold of 55 pounds per day if facilities replace ICEs with gas turbines (142 pounds per day).

Similar to the air quality analysis for PAR 1110.2, the air quality analysis for Alternative B includes the assumption that operators of 169 non-biogas engines would replace existing engines with electric motors. Based on this assumption, it is expected that Alternative B would also reduce CO2 emissions. Similar to PAR 1110.2, Alternative B would require a technology assessment, but it would be required in 2012 instead of 2010. The technology assessment would include the number of non-biogas engines that have been replaced with electric motors. As with PAR 1110.2, any shortfalls in CO2 emission reductions would be made up by other measures identified at the time the technology assessment is completed. For overall CO2 reductions, approximately 14 engines would need to be replaced. Table 5-13 summarizes the overall CO2 reduction analysis.

Table 5-13
Average Number of ICE Engines Replaced with Electric Motors Needed for CO2 Reductions under Alternative B

Description	Proposed Project CO2, ton/10 years	No Electrification CO2, ton/10 years	Reduction in CO2 from Electrification	Average CO2 Savings per Motor	Average No of Motor for CO2 Reductions
SCR	(264,959)	11,516	276,475	1,636	8
Replace ICE with Gas Turbine	(104,642)	9,157	113,799	673	14
Replace ICE Microturbine	(266,520)	9,955	276,475	1,636	7
Replace LFG w LNG, DG w Turbines	(1,228,165)	(951,690)	276,475	1,636	0
Replace LFG w LNG, DG w Microturbines	(1,227,406)	(950,932)	276,475	1,636	0

Electric motors were assumed to have a ten year lifespan.

Energy

Expanding the low use exception would reduce the number of engines that would need to be retrofitted with oxidation catalyst. The exception of lean-burn engines from the NOx CEMS requirements would reduce the amount of electricity required to operate CEMS at seven facilities. This aspect of Alternative B is not expected to change the magnitude of adverse energy impacts previously identified for PAR 1110.2. There would be an incremental reduction in the amount of diesel fuel required for catalyst disposal and replacement trips because fewer engines would be retrofitted with oxidation catalysts. As indicated in the analysis of PAR 1110.2, most of the adverse energy impacts are anticipated as a result of modifications at biogas facilities. Because the concentration provision in Alternative B is identical to the concentration provision in PAR 1110.2, potential adverse energy impacts from compliance activities at biogas facilities would be similar to those identified for PAR 1110.2. Potential adverse energy impacts include increased demand for diesel resulting from truck trips associated with removal and replacement of catalysts and ammonia delivery. Alternative B would allow the same compliance options at biogas facilities that are available for PAR 1110.2. As a result, Alternative B would generate energy impacts equivalent to PAR 1110.2. Like PAR 1110.2 Alternative B would increase demand for electricity, while reducing demand for natural gas. Further, losses of renewable energy in one sector would be made up by increases in renewable energy in another sector. Therefore, overall Alternative B, like PAR 1110.2, is not expected to generate significant adverse energy impacts.

Hazards/Hazardous Materials

Hazards and hazardous materials impacts identified for PAR 1110.2 were associated with compliance activities at biogas facilities. Because Alternative B was analyzed using the same compliance scenarios as PAR 1110.2, hazard/hazardous materials impacts would be equivalent to those identified for PAR 1110.2. Secondary hazards and hazardous materials impacts are associated only with control technologies (in particular retrofitting engines with SCR or replacing engines with LNG plants) expected to be used at biogas facilities.

Biogas facilities that install SCR or NOxTech systems would have potential adverse impacts from ammonia accidental releases. The furthest distance to the significant threshold ERPG2 concentration of 150 ppm of ammonia modeled would be 0.1 miles from the catastrophic failure of an ammonia storage tank. ERPG-2 concentrations are the maximum airborne concentration below which it is believed nearly all individuals could be exposed for up to one hour without experiencing or developing irreversible or other serious health effects or symptoms that could impair their ability to take protective action. For the off-site impacts analysis, it was assumed that ammonia storage tanks would be constructed close to where existing ICE is located. Based on GIS modeling and surveys of biogas facilities, there would be facilities with ammonia tanks that are less than 0.1 miles from the property line. Some facilities have sensitive receptors within 0.1 miles of ammonia storage sites; therefore Alterantive B is significant for accidental releases from ammonia storage.

The transport of aqueous ammonia is not likely to significantly impact receptors because conditions are not typically that would result in pooling of the aqueous ammonia. For example, an accidental release of aqueous ammonia on roadways is unlikely to result in pooling as there are no barriers to impede flow, so it would likely flow off roads onto porous ground where it would be absorbed or underground into storm drains.

Biogas facilities operators who install LNG plants would have potential adverse impacts from LNG accidental releases. The furthest distance to the significance threshold of one psi overpressure is 0.2 mile. One psi overpressure may cause partial demolition of houses, shattering of glass windows and serious injuries to people. For the off-site impacts analysis, it was assumed that LNG storage tanks would be constructed close to where the existing ICEs are located. Based on GIS modeling and surveys of biogas facilities, there would be facilities with LNG tanks that are less than 0.1 mile from the property line. Therefore, facility operators who choose to replace ICEs with biogas to LNG plants could create significant adverse impacts to receptors within 0.2 mile of the LNG storage tanks.

No facilities have schools within one-quarter mile; therefore, Alternative D would not significantly adversely affect schools within a quarter mile. No facilities are within two miles of an airport or airfield; therefore, would not adversely significantly impact those working at or near an airport or airfield. However, facilities would have sensitive receptors within 0.2 mile of LNG storage sites. No mitigation measures were identified that could reduce this potential adverse hazard impact to less than significant.

During transport, LNG is compressed by refrigeration, and it is not flammable in its liquid state. However, an accident could produce a pool of LNG that could evaporate and ignite, forming a flammable cloud, BLEVE, or a ruptured tank could rocket away and ignite. Receptors within 0.3 mile of the delivery truck may be adversely affected by any of these scenarios. A tank that ruptures and rockets away could adversely affect a zone covering greater than 0.3 mile around the tank from the initial accident site to the final resting place of the LNG delivery tank. Therefore, Alternative B is considered significant for accidental releases of LNG during transport.

Solid/Hazardous Waste

It is anticipated that Alternative B would generate less solid/hazardous wastes then PAR 1110.2, because fewer oxidation catalysts would be installed as a result of the compliance exception extended to non-biogas facilities. Metals from oxidation catalysts may be recycled, but eventually would become waste. While it is assumed that oxidation catalysts would be considered "designated waste" that can be disposed of in Class II or III landfills, some oxidation catalyst may be classified as hazardous waste requiring disposal in Class I landfills.

Similar to the analysis for PAR 1110.2, SCAQMD staff analyzed different scenarios in which it was assumed that all biogas ICEs would be replaced with alternative compliance options such as turbines, biogas to LNG plants, etc. Since no other scenarios provide a more conservative analysis than total removal and replacement of existing engines, these same scenarios were applied to the analysis of Alternative B.

It is expected that Alternative B would generate incrementally less solid/hazardous waste impacts than PAR 1110.2 because of the exception applied to non-biogas engines. Overall Alternative B, like PAR 1110.2, is not expected to generate significant adverse solid/hazardous waste impacts.

Alternative C – Enhanced Enforcement Alternative

Aesthetics

Alternative C would maintain the same pollution control requirements that are currently in Rule 1110.2. As a result, Alternative C would not substantially change the size or configuration of existing engines onsite. Alternative C, like PAR 1110.2 would require operators of specified categories of ICEs to install CEMs, requiring minor construction at affected facilities. Neither the construction of CEMs nor operation of this equipment is expected to change the visual character of affected facilities. Alternative C would likely require additional infrastructure for source testing and additional monitoring equipment. The additional infrastructure and monitoring equipment is also not expected to change the visual character of the affected facilities or surroundings. Therefore, Alternative C, like PAR 1110.2, is not expected to create significant adverse aesthetics impacts. Aesthetics impacts from implementing Alternative C would be less than for PAR 1110.2 since alternative compliance options that may occur under PAR 1110.2 may be slightly more noticeable.

Air Quality

Because Alternative C does not impose additional concentration limit requirements like the proposed project and other alternatives, but does impose measures such as installation of CEMs, potential air quality impacts from construction activities would be substantially less than for the proposed project. Relative to operational activities, Alternative C is expected to generate emission reductions compared to the baseline inventory by enhancing enforcement of the existing emission control requirements through installation of CEMs, additional inspection and monitoring, etc. Alternative C, however, may generate diesel exhaust emission during operation from source testing vehicle trips (source testing vehicles may be gasoline powered). However, SCAQMD staff expects only one additional source test per facility every two years. Health risk from a single vehicle trip every other year would be negligible.

Table 5-14 presents the inventory of emissions from all engines that would be subject to Alternative C by year in which different requirements become effective. As with PAR 1110.2, construction and operational emissions are expected to overlap. Table 5-15 shows the net effect on emissions from affected engines, taking into consideration both construction emission increases and emission reductions anticipated from enhanced enforcement activities.

Table 5-14
Total Emissions Inventory by Year
Anticipated from Implementing Alternative C

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5 lb/day	~~CO2, ton/year~~
2008	~~9,152~~ 9,155	~~54,086~~ 54,104	~~2,489~~ 2,494	~~547~~ 547	~~880.8~~ 881.3	~~878.6~~ 879.1	~~1,237,862~~
2009	~~6,853~~ 6,856	~~22,683~~ 22,701	~~1,848~~ 1,853	~~547~~ 547	~~874.0~~ 874.5	~~872.0~~ 872.5	~~1,246,022~~
2010	~~6,864~~ 6,867	~~22,233~~ 22,251	~~1,519~~ 1,524	~~545~~ 545	~~874.0~~ 874.5	~~872.0~~ 872.5	~~1,238,803~~
2011	~~6,820~~ 6,823	~~21,989~~ 22,007	~~1,517~~ 1,522	~~545~~ 545	~~874.0~~ 874.5	~~872.0~~ 872.5	~~1,238,875~~

As indicated in Table 5-15, Alternative C is not expected to create significant averse air quality impacts. As already noted in the project description for Alternative C, since Alternative C does not include additional emission control requirements that could result in retrofitting existing engines with SCR, no ammonia slip emissions would be generated. Consequently, Alternative is concluded to be the least toxic alternative.

Energy

Alternative C would have minor adverse energy impacts, from additional monitoring equipment and vehicle travel associated with additional source testing. Approximately 567 MW-hours per year would be required for CEMS, ATRC and analyzers. Based on the available 120,194 GW-hours per year in southern California, this would be less than one percent of the available electricity (4.73×10^{-7} percent).

Table 5-15
Net Emissions Effect from Implementing Alternative C
Compared to Baseline

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5 lb/day	~~CO2, ton/year~~
2008	~~(43)~~ (40)	~~(157)~~ (139)	~~(3)~~ 1	~~(5)~~ (4)	~~3.9~~ 4.4	~~3.4~~ 3.9	~~(12,184)~~
2009	~~(2,331)~~ (2,339)	~~(32,010)~~ (31,542)	~~(974)~~ (640)	~~(6)~~ (4)	~~(3)~~ (2.4)	~~(3)~~ (2.7)	~~(11,244)~~
2010	~~(2,331)~~ (2,328)	~~(32,010)~~ (31,992)	~~(974)~~ (969)	~~(6)~~ (6)	~~(3)~~ (2.4)	~~(3)~~ (2.7)	~~(11,244)~~
2011	~~(2,375)~~ (2,372)	~~(32,254)~~ (32,236)	~~(976)~~ (971)	~~(6)~~ (6)	~~(3)~~ (2.4)	~~(3)~~ (2.7)	~~(11,172)~~

Numbers in parentheses represent emission reductions.

Since Alternative C would not require emissions control equipment, it would not affect electrical production at biogas facilities. Since it would not affect electrical production at biogas facilities it would not affect renewable energy goals.

Alternative C has a higher natural gas allowance in connection with the combustion of biogas or digester gas compared to PAR 1110.2, 25 percent versus 10 percent respectively. As a result, Alternative C is not expected to reduce natural gas usage at affected biogas facilities as would be the case under PAR 1110.2. Regardless of this effect and, based on the above analysis, Alternative C is not expected to generate significant adverse energy impacts.

Hazards/Hazardous Materials

The analysis of potential hazard/hazardous materials impacts from implementing PAR 1110.2 in Chapter 4 concluded that the alternative compliance option of replacing existing biogas ICEs with biogas to LNG plants could produce significant adverse explosion and fire impacts to nearby receptors. Because Alternative C would impose no additional compliance requirements, it would not be expected to generate any significant adverse hazard impacts compared to PAR 1110.2. Further, hazards would not be generated from increased monitoring and source testing. Therefore, Alternative C is not expected to create significant adverse hazards/hazardous materials impacts.

Solid/Hazardous Waste

Chapter 4 concluded that, although there could be some solid waste impacts from disposal of ICE that are replaced with alternative compliance options and disposal of spent catalysts, local landfills and/or hazardous waste landfills in California could accommodate this increase in waste disposal. As a result, solid/hazardous waste impacts were concluded to be less than significant. Because Alternative C would impose no additional compliance requirements and no additional solid or hazardous waste would be generated from increased monitoring and source testing, Alternative C would not be expected to generate any significant adverse solid or hazardous waste impacts compared to PAR 1110.2.

Alternative D – BACT Alternative

Aesthetics

Alternative D would have similar adverse aesthetic impacts to PAR 1110.2. Alternative D may have incrementally greater adverse visual impacts at both non-biogas and biogas facilities, because the lower CO compliance limit may require larger control units at affected facilities. While CO control equipment may be physically larger, they would generally have the same visual characteristics and, therefore, would be indistinguishable from the units used to comply with PAR 1110.2. It is possible that there may be additional costs associated with controlling CO emissions to a lower concentration and, as a result, could create a greater impetus for operators to replace ICEs with alternative systems. However, the analysis of impacts from implementing PAR 1110.2 already assumed that operators of all affected biogas engines would replace ICEs with alternative systems. This same assumption would apply to Alternative D as a worst-case. Therefore, since the worst-case scenarios for PAR 1110.2 and Alternative D are the same, the worst-case adverse impacts are considered to be equivalent. For example, under either PAR 1110.2 or Alternative D operators of biogas engines could potentially retrofit engines with control systems (SCR, NOxTech, etc.) or replace ICEs with alternative compliance options (microturbines, turbines, or biogas LNG plants). As a result, the worse-case adverse impacts from implementing Alternative D would be similar those identified from implementing PAR 1110.2. Therefore, it is concluded that Alternative D could create potentially significant adverse aesthetics impacts.

Air Quality

Construction

Alternative D would likely require more construction than PAR 1110.2, since Alternative D does not include a low usage exemption from compliance limits, but does require a lower CO compliance limit of 70 ppm than PAR 1110.2 (250 ppm). However, Alternative D would add an additional two years to the compliance dates proposed in PAR 1110.2. Operators who have existing equipment that is less than 10 years old in 2008 would receive an additional two years to comply with the proposed emission concentration requirements. An additional two years to comply with the final concentration requirements would result in fewer construction activities overlapping, thus, potentially reducing peak day construction impacts compared to PAR 1110.2.

Operational

Alternative D would generate the same NOx and VOC emission reductions as PAR 1110.2, but is expected to achieve greater CO emission reductions than PAR 1110.2 because the CO compliance limit under Alternative D is 70 ppm, which is lower than the CO limit for PAR 1110.2. The control technologies used to reduce NOx and VOC emissions will also reduce CO emissions. It is expected that these technologies would reduce CO to 70 ppm; however, facility operators have stated that it would be difficult to keep all three pollutants under the compliance limits of Alternative D.

Since CO is a product of incomplete combustion, the lower CO concentration compliance limit may generate greater CO2 emissions. Assuming that the same number of non-biogas engines are replaced with electric motors as would be the case under PAR 1110.2, CO2 emission reduction benefits under Alternative would be less than anticipated under PAR 1110.2.

Because the final biogas concentration limit compliance dates for Alternative D are delayed by two years with the natural life allowance compared to PAR 1110.2, anticipated emission reductions would occur later. Allowing an additional two years to comply with the emission concentration requirements in Alternative D may allow the emergence of new air pollution control technologies that are more efficient and with fewer secondary impacts than currently available control technologies. Such advances in technology are not currently reasonably foreseeable and, as a result, the analysis of impacts for Alternative D assumes the same technologies will be used as under PAR 1110.2.

The air quality effects of implementing Alternative D are presented in the same way as they were for PAR 1110.2. Tables 5-16 through 5-20 present the total emissions inventory by compliance year that takes into consideration the declining operating emissions inventory from affected equipment reducing emissions to comply with Alternative D and increased construction emissions from installing air pollution control and monitoring equipment or installing alternative compliance technologies. Table 5-16 shows the remaining emissions by compliance year and construction emissions for the compliance option of all biogas plant operators retrofitting using SCR. Table 5-17 shows the remaining emissions by compliance year and construction emissions for the compliance option of all biogas plant operators replacing ICEs with gas turbines. Table 5-18 shows the remaining emissions by compliance year and construction emissions for the compliance option of biogas operators replacing ICEs with microturbines. Table 5-19 shows the remaining emissions by compliance year and construction emissions for the compliance option of biogas operators replacing ICEs with digester plant and LNG plants at landfills. Table 5-20 shows the remaining emissions by compliance year and construction emissions for the compliance option of operators replacing ICEs with microturbines and landfill gas facility operators replacing ICEs with LNG plants.

Table 5-16
Net Criteria Emission Inventories from Non-biogas Facilities and the SCR Compliance Option for Biogas Facilities under Alternative D

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5 lb/day
2008	~~9,089~~ 9,094	~~53,909~~ 53,942	~~2,470~~ 2,479	~~543.9~~ 545	~~876.8~~ 878	~~874.7~~ 876
2009	~~6,410~~ 6,415	~~22,399~~ 22,432	~~1,790~~ 1,799	~~543~~ 544	~~858~~ 859	~~856~~ 857
2010	~~5,964~~ 5,969	~~15,818~~ 15,851	~~1,267~~ 1,276	~~534~~ 535	~~844~~ 845	~~842~~ 843
2011	~~5,591~~ 5,596	~~11,733~~ 11,766	~~1,200~~ 1,209	~~529~~ 530	~~834~~ 835	~~831~~ 832
2012	5,420	11,657	1,177	528	825	823
2014	3,706	3,504	425	74	697	696
2015	3,712	3,500	423	74	697	696

Table 5-17
Net Criteria Emission Inventories from Non-biogas Facilities and the Gas Turbines Option for Biogas Facilities under Alternative D

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5 lb/day
2008	~~9,089~~ 9,094	~~53,909~~ 53,942	~~2,470~~ 2,479	~~543.9~~ 545	~~876.8~~ 878	~~874.7~~ 876
2009	~~6,410~~ 6,415	~~22,399~~ 22,432	~~1,790~~ 1,799	~~543~~ 544	~~858~~ 859	~~856~~ 857
2010	~~5,964~~ 5,969	~~15,818~~ 15,851	~~1,267~~ 1,276	~~534~~ 535	~~844~~ 845	~~842~~ 843
2011	~~5,586~~ 5,591	~~11,731~~ 11,764	~~1,199~~ 1,208	~~529~~ 530	~~833~~ 834	~~831~~ 832
2012	5,444	11,784	1,189	529	832	830
2014	4,878	5,532	502	538	1,019	1,017
2015	4,884	5,527	500	538	1,019	1,017

Table 5-18
Net Criteria Emission Inventories from Non-biogas Facilities and the Microturbine Compliance Option for Biogas Facilities under Alternative D

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5 lb/day
2008	~~9,089~~ 9,094	~~53,909~~ 53,942	~~2,470~~ 2,479	~~543.9~~ 545	~~876.8~~ 878	~~874.7~~ 876
2009	~~6,410~~ 6,415	~~22,399~~ 22,432	~~1,790~~ 1,799	~~543~~ 544	~~858~~ 859	~~856~~ 857
2010	~~5,964~~ 5,969	~~15,818~~ 15,851	~~1,267~~ 1,276	~~534~~ 535	~~844~~ 845	~~842~~ 843
2011	~~5,586~~ 5,591	~~11,731~~ 11,764	~~1,199~~ 1,208	~~529~~ 530	~~833~~ 834	~~831~~ 832
2012	5,463	11,854	1,196	529	837	835
2014	3,913	4,344	607	538	760	758
2015	3,919	4,339	605	538	760	758

Table 5-19
Net Criteria Emission Inventories from Non-biogas Facilities and the Gas Turbines at Digester Gas Facilities and LNG Facilities at Landfills Compliance Option for Biogas Facilities Under Alternative D

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5 lb/day
2008	~~9,089~~ 9,094	~~53,909~~ 53,942	~~2,470~~ 2,479	~~543.9~~ 545	~~876.8~~ 878	~~874.7~~ 876
2009	~~6,410~~ 6,415	~~22,399~~ 22,432	~~1,790~~ 1,799	~~543~~ 544	~~858~~ 859	~~856~~ 857
2010	~~5,964~~ 5,969	~~15,818~~ 15,851	~~1,267~~ 1,276	~~534~~ 535	~~844~~ 845	~~842~~ 843
2011	~~6,072~~ 6,077	~~11,931~~ 11,964	~~1,257~~ 1,266	~~529~~ 530	~~872~~ 873	~~857~~ 858
2012	5,944	12,230	1,267	529	896	882
2014	4,742	4,862	546	211	911	896
2015	4,373	4,692	495	211	878	876

Table 5-20
Net Criteria Emission Inventories from Non-biogas Facilities and the Microturbines at Digester Gas Facilities and LNG Facilities at Landfills Compliance Option for Biogas Facilities under Alternative D

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5 lb/day
2008	~~9,089~~ 9,094	~~53,909~~ 53,942	~~2,470~~ 2,479	~~543.9~~ 545	~~876.8~~ 878	~~874.7~~ 876
2009	~~6,410~~ 6,415	~~22,399~~ 22,432	~~1,790~~ 1,799	~~543~~ 544	~~858~~ 859	~~856~~ 857
2010	~~5,964~~ 5,969	~~15,818~~ 15,851	~~1,267~~ 1,276	~~534~~ 535	~~844~~ 845	~~842~~ 843
2011	~~6,072~~ 6,077	~~11,931~~ 11,964	~~1,257~~ 1,266	~~529~~ 530	~~872~~ 873	~~857~~ 858
2012	5,963	12,280	1,272	529	899	885
2014	4,206	3,707	483	75	736	722
2015	3,837	3,537	433	74	703	702

Table 5-21 shows the net emissions effect (emission reduction) by compliance year, which includes construction emissions, for the compliance option of all biogas plant operators retrofitting using SCR. Table 5-22 shows the net emissions effect (emission reduction) by compliance year, which includes construction emissions, for the compliance option of all biogas plant operators replacing ICEs with gas turbines. Table 5-23 shows the net emissions effect (emission reduction) by compliance year, which includes construction emissions, for the compliance option of biogas operators replacing ICEs with microturbines. Table 5-24 shows the net emissions effect (emission reduction) by compliance year, which includes construction emissions, for the compliance option of biogas operators replacing ICEs with digester plant and LNG plants at landfills. Table 5-25 shows the net emissions effect (emission reduction) by compliance year, which includes construction emissions, for the compliance option of operators replacing ICEs with microturbines and landfill gas facility operators replacing ICEs with LNG plants.

Table 5-21
Net Criteria Emission Effects from Non-Biogas Facilities and Installing SCR at All Biogas Plants -Total Compared to Baseline under Alternative D

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5 lb/day
2008	~~(106)~~ (100)	~~(334)~~ (301)	~~(22)~~ (14)	~~(7.5)~~ (6.9)	~~(0.1)~~ 0.8	~~0.4~~ 0.4
2009	~~(3,231)~~ (3,225)	~~(38,425)~~ (38,392)	~~(1,226)~~ (1,217)	~~(18)~~ (17)	~~(33)~~ (32)	~~(33)~~ (32)
2010	~~(3,231)~~ (3,225)	~~(38,425)~~ (38,392)	~~(1,226)~~ (1,217)	~~(18)~~ (17)	~~(33)~~ (32)	~~(33)~~ (32)
2011	~~(3,603)~~ (3,598)	~~(42,510)~~ (42,477)	~~(1,293)~~ (1,284)	~~(23)~~ (22)	~~(43)~~ (42)	~~(44)~~ (43)
2012	(3,775)	(42,586)	(1,315)	(23)	(52)	(52)
2014	(5,489)	(50,739)	(2,068)	(477)	(180)	(180)
2015	(5,483)	(50,743)	(2,070)	(477)	(179)	(179)

Numbers in parentheses represent emission reduction.

Table 5-22
Net Criteria Emission Effects from Non-Biogas Facilities and Gas Turbines at All Biogas Plants -Total Compared to Baseline under Alternative D

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5 lb/day
2008	~~(106)~~ (100)	~~(334)~~ (301)	~~(23)~~ (14)	~~(7.5)~~ (6.9)	~~(0.1)~~ 0.8	~~0.4~~ 0.4
2009	~~(3,231)~~ (3,225)	~~(38,425)~~ (38,392)	~~(1,194)~~ (1,217)	~~(18)~~ (17)	~~(33)~~ (32)	~~(33)~~ (32)
2010	~~(3,231)~~ (3,225)	~~(38,425)~~ (38,392)	~~(1,226)~~ (1,217)	~~(18)~~ (17)	~~(33)~~ (32)	~~(33)~~ (32)
2011	~~(3,609)~~ (3,603)	~~(42,512)~~ (42,479)	~~(1,294)~~ (1,285)	~~(23)~~ (22)	~~(43)~~ (43)	~~(44)~~ (43)
2012	(3,751)	(42,459)	(1,304)	(23)	(44)	(45)
2014	(4,317)	(48,711)	(1,991)	(13)	142	142
2015	(4,311)	(48,716)	(1,993)	(13)	142	142

Numbers in parentheses represent emission reduction.

Table 5-23
Net Criteria Emission Effects from Non-Biogas Facilities and Microturbines at All Biogas Plants -Total Compared to Baseline under Alternative D

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5 lb/day
2008	~~(106)~~ (100)	~~(334)~~ (301)	~~(22)~~ (14)	~~(7.5)~~ (6.9)	~~(0.1)~~ 0.8	~~0.4~~ 0.4
2009	~~(3,231)~~ (3,225)	~~(38,425)~~ (38,392)	~~(1,226)~~ (1,217)	~~(18)~~ (17)	~~(33)~~ (32)	~~(33)~~ (32)
2010	~~(3,231)~~ (3,225)	~~(38,425)~~ (38,392)	~~(1,226)~~ (1,217)	~~(18)~~ (17)	~~(33)~~ (32)	~~(33)~~ (32)
2011	~~(3,609)~~ (3,603)	~~(42,512)~~ (42,479)	~~(1,294)~~ (1,285)	~~(23)~~ (22)	~~(43)~~ (43)	~~(44)~~ (43)
2012	(3,732)	(49,389)	(1,297)	(22)	(40)	(40)
2014	(5,282)	(49,899)	(1,886)	(13)	(117)	(117)
2015	(5,275)	(49,904)	(1,888)	(13)	(117)	(117)

Numbers in parentheses represent emission reduction.

Table 5-24
Net Criteria Emission Effects from Non-Biogas Facilities and Gas Turbines at Digester Gas Facilities and LNG Facilities at Landfills -Total Compared to Baseline under Alternative D

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5 lb/day
2008	~~(106)~~ (100)	~~(334)~~ (301)	~~(22)~~ (14)	~~(7.5)~~ (6.9)	~~(0.1)~~ 0.8	~~0.4~~ 0.4
2009	~~(3,231)~~ (3,225)	~~(38,425)~~ (38,392)	~~(1,226)~~ (1,217)	~~(18)~~ (17)	~~(33)~~ (32)	~~(33)~~ (32)
2010	~~(3,231)~~ (3,225)	~~(38,425)~~ (38,392)	~~(1,226)~~ (1,217)	~~(18)~~ (17)	~~(33)~~ (32)	~~(33)~~ (32)
2011	~~(3,123)~~ (3,117)	~~(42,312)~~ (42,279)	~~(1,236)~~ (1,227)	~~(22)~~ (22)	~~(5)~~ (4)	~~(18)~~ (17)
2012	(3,251)	(42,013)	(1,226)	(22)	19.6	7.24
2014	(4,453)	(49,381)	(1,947)	(340)	33.7	21.30
2015	(4,821)	(49,551)	(1,998)	(340)	1.2	0.75

Numbers in parentheses represent emission reduction.

Table 5-25
Net Criteria Emission Effects from Non-Biogas Facilities and Microturbines at Digester Gas Facilities and LNG Facilities at Landfills -Total Compared to Baseline under Alternative D

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5 lb/day
2008	~~(106)~~ (100)	~~(334)~~ (301)	~~(22)~~ (14)	~~(7.5)~~ (6.9)	~~(0.1)~~ 0.8	~~0.4~~ 0.4
2009	~~(3,231)~~ (3,225)	~~(38,425)~~ (38,392)	~~(1,226)~~ (1,217)	~~(18)~~ (17)	~~(33)~~ (32)	~~(33)~~ (32)
2010	~~(3,231)~~ (3,225)	~~(38,425)~~ (38,392)	~~(1,226)~~ (1,217)	~~(18)~~ (17)	~~(33)~~ (32)	~~(33)~~ (32)
2011	~~(3,123)~~ (3,117)	~~(42,312)~~ (42,279)	~~(1,236)~~ (1,227)	~~(22)~~ (22)	~~(5)~~ (4)	~~(18)~~ (17)
2012	(3,232)	(41,963)	(1,220)	(22)	22	10
2014	(4,989)	(50,536)	(2,009)	(477)	(141)	(153)
2015	(5,358)	(50,706)	(2,060)	(477)	(173)	(174)

Numbers in parentheses represent emission reduction.

As can be seen in Table 5-22, the worst-case operational emissions scenario would be if all biogas operators replace ICEs with gas turbines. In this scenario, PM2.5 emissions exceed the applicable operational significance threshold. No other compliance scenarios resulted in significant adverse air quality impacts. Air quality impact conclusions for Alternative D are the same as the air quality impact conclusions for PAR 1110.2.

Similar to the air quality analysis for PAR 1110.2, the air quality analysis for Alternative D includes the assumption that operators of 169 non-biogas engines would replace existing engines with electric motors. Based on this assumption, it is expected that Alternative D would also reduce CO2 emissions. Similar to PAR 1110.2, Alternative D would require a technology assessment, but it would be required in 2012 instead of 2010. The technology assessment would include the number of non-biogas engines that have been replaced with electric motors. As with PAR 1110.2, any shortfalls in CO2 emission reductions would be made up by other measures identified at the time the technology assessment is completed and presented to the Governing Board. For overall CO2 reductions, approximately 27 engines would need to be replaced. Table 5-26 summarizes the overall CO2 reduction analysis.

Table 5-26
Average Number of ICE Engines Replaced with Electric Motors Needed for CO2 Reductions under Alternative D

Description	Proposed Project CO2, ton/year	No Electrification CO2, ton/year	Reduction in CO2 from Electrification	Average CO2 Savings per Motor	Average No of Motor for CO2 Reductions
SCR	(248,723)	32,719	281,443	1,665	20
Replace ICE with Gas Turbine	(100,168)	18,664	118,831	703	27
Replace ICE Microturbine	(261,981)	19,462	281,443	1,665	12
Replace LFG w LNG, DG w Turbines	(1,223,610)	(942,167)	281,443	1,665	0
Replace LFG w LNG, DG w Microturbines	(1,222,851)	(941,408)	281,443	1,665	0

Electric motors were assumed to have a ten year lifespan.
Numbers in parentheses represent emission reductions.

Energy

In practice, more biogas facility operators may replace ICEs with alternative compliance technologies such as boilers, turbines, microturbines, electrification, and biogas to LNG plants under Alternative D than PAR 1110.2. However, because actual compliance options were not known and to provide a conservative analysis for PAR 1110.2, SCAQMD staff analyzed different scenarios in which it was assumed that all ICEs would be replaced with alternative compliance options such as turbines, biogas to LNG plants, etc. Since no other scenarios provide a more conservative analysis than total removal and replacement of existing engines, these same scenarios were applied to the analysis of Alternative D. As a result, Alternative D would generate energy impacts similar to PAR 1110.2. Like PAR 1110.2 Alternative D would increase demand for electricity, while reducing demand for natural gas. Further, losses of renewable energy in one sector would be made up by increases in renewable energy in another sector. Therefore, overall Alternative D, like PAR 1110.2, is not expected to generate significant adverse energy impacts.

Hazards/Hazardous Materials

Because Alternative D was analyzed using the same compliance scenarios as PAR 1110.2, hazard/hazardous materials impacts would be equivalent to those identified for PAR 1110.2. ICEs at non-biogas facilities would only require monitoring equipment or oxidation catalysts. Neither of these compliance requirements at non-biogas facilities includes use of hazardous materials that would adversely affect the public. Secondary hazards and hazardous materials impacts are associated only with control technologies (in particular retrofitting engines with SCR or replacing engines with LNG plants) expected to be used at biogas facilities.

Biogas facility operators could install SCR on existing ICEs or replace ICEs with biogas to LNG plants under either Alternative D or PAR 1110.2. The furthest distance to the significant threshold ERPG2 concentration of 150 ppm of ammonia modeled would be 0.1 miles from the catastrophic failure of an ammonia storage tank. ERPG-2 concentrations are the maximum airborne concentration below which it is believed nearly all individuals could be exposed for up to one hour without experiencing or developing irreversible or other serious health effects or symptoms that could impair their ability to take protective action. Ammonia storage tanks if installed within 0.1 mile of the property boundary may significantly adversely impact sensitive or residential receptors within 0.1 mile of a catastrophic accidental failure of the ammonia storage tank.

The transport of aqueous ammonia is not likely to significantly impact receptors because conditions are not typically that would result in pooling of the aqueous ammonia. For example, an accidental release of aqueous ammonia on roadways is unlikely to result in pooling as there are no barriers to impede flow, so it would likely flow off roads onto porous ground where it would be absorbed or underground into storm drains.

Biogas facilities operators who install LNG plants would have potential adverse impacts from LNG accidental releases. The furthest distance to the significance threshold of one psi overpressure is 0.2 mile. One psi overpressure may cause partial demolition of houses, shattering of glass windows and serious injuries to people. For the off-site impacts analysis, it was assumed that LNG storage tanks would be constructed close to where the existing ICEs are located. Based on GIS modeling and surveys of biogas facilities, there would be facilities with LNG tanks that are less than 0.1 mile from the property line. Therefore, facility operators who choose to replace ICEs with biogas to LNG plants could create significant adverse impacts to receptors within 0.2 mile of the LNG storage tanks.

No facilities have schools within one-quarter mile; therefore, Alternative D would not significantly adversely affect schools within a quarter mile. No facilities are within two miles of an airport or airfield; therefore, would not adversely significantly impact those working at or near an airport or airfield. However, facilities would have sensitive receptors within 0.2 mile of LNG storage sites. No mitigation measures were identified that could reduce this potential adverse hazard impact to less than significant.

During transport, LNG is compressed by refrigeration, and it is not flammable in its liquid state. However, an accident could produce a pool of LNG that could evaporate and ignite, forming a flammable cloud, BLEVE, or a ruptured tank could rocket away and ignite. Receptors within 0.3 mile of the delivery truck may be adversely affected by any of these scenarios. A tank that ruptures and rockets away could adversely affect a zone covering greater than 0.3 mile around the tank from the initial accident site to the final resting place of the LNG delivery tank. Therefore, Alternative D is considered significant for accidental releases of LNG during transport.

Solid/Hazardous Waste

The replacement or installation of oxidation catalyst for non-biogas facilities would be the same for Alternative D and the existing project. However, in practice, more biogas facility operators may replace ICEs with alternative compliance technologies such as boilers, turbines, microturbines, electrification, and biogas to LNG plants under Alternative D than

PAR 1110.2. Because actual compliance options were not known and to provide a conservative analysis for PAR 1110.2, SCAQMD staff analyzed different scenarios in which it was assumed that all biogas ICEs would be replaced with alternative compliance options such as turbines, biogas to LNG plants, etc. Since no other scenarios provide a more conservative analysis than total removal and replacement of existing engines, these same scenarios were applied to the analysis of Alternative D. As a result, Alternative D would generate solid/hazardous waste impacts equivalent to PAR 1110.2. Overall Alternative D, like PAR 1110.2, is not expected to generate significant adverse solid/hazardous waste impacts.

Comparison of the Relative Merits of the Project Alternatives by Environmental Topic

The following subsections summarize the effects of PAR 1110.2 and the project alternatives by environmental category.

Aesthetics

Alternative A would not be expected to generate any aesthetics impacts because it would not require any additional emission reductions or compliance modifications. Of the remaining alternatives, Alternative C is expected to generate less than significant aesthetic impacts because it only requires the addition of source testing infrastructure, CEMS, ATRCs and analyzers. The analysis of PAR 1110.2 concluded that it has the potential to generate significant adverse aesthetics impacts primarily from removal of ICEs and the installation of alternative technologies at biogas facilities. Because Alternatives B and D contain the same requirements as PAR 1110.2 for engines at biogas facilities, they would be expected to create significant adverse aesthetics impacts equivalent to PAR 1110.2.

Air Quality

Although Alternative D would generate the same NOx and VOC emission reductions as PAR 1110.2, Alternative D would generate more CO emission reductions than PAR 1110.2 because of the lower CO compliance limit (Table 5-27). Because Alternative B would extend the compliance exception for non-biogas engines, it would generate more emissions than PAR 1110.2. Alternative C does not contain any emission reduction requirements and, as a result, would generate as much emission reductions as the proposed project and other alternatives. However, because of the enforcement enhancements contained in Alterative C, it is expected to prevent or limit future violations of the existing emission concentration requirements in Rule 1110.2. Alternative A would have the least beneficial effect on air quality because, not only would it not produce any emission reductions, it contains no enhanced enforcement provisions that reduce future violations of the exiting provisions in Rule 1110.2. The emissions in Table 5-27 represent the net effects of both construction emission increases, secondary operational emission increase impacts, and direct emission reductions from each potential project.

Table 5-27
Worst-Case Emissions Increases or Reductions from Each Alternative

Description	Year	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5, lb/day
Proposed Project	2014	(5,433)	(46,868)	(1,955)	(13.0)	142	142
Alternative A*	-	0	0	0	0	0	0
Alternative B	2014	(4,307)	(46,831)	(1,953)	(13.0)	142	142
Alternative C	2011	(43)	(157)	(3.3)	(4.7)	3.9	3.4
Alternative D	2015	(4,311)	(48,716)	(1,993)	(13.0)	142	142

Numbers in parentheses represent emission reductions.
* Estimated excess emissions over the current Rule 1110.2 are reported for Alternative A.

Toxic Air Contaminate Emissions

Alternative A is not expected to generate any addition air toxics because imposes no additional requirements for affected engines. Alternative C would generate negligible (less than significant) cancer risks from diesel particulate exhaust from trucks used to visit sites for source testing. The reason for this conclusion is that increased source testing would add one additional trip to affected facilities every two years. The analysis of PAR 1110.2 concluded that the proposed project could generate significant adverse cancer risk impacts at biogas and non-biogas facilities where operators install emergency backup diesel engines. Cancer risk impacts from Alternatives B and D are expected to be equivalent to PAR 1110.2, since operators at the same biogas and non-biogas facility may install diesel emergency backup generators because existing ICEs may be replace with alternative compliance options (e.g., LNG plants that also generate truck trips to pick up LNG).

Greenhouse Gas Emissions

Neither Alternative A nor Alternative C is expected to reduce CO2 emissions. Because the same assumptions were used for PAR 1110.2 and Alternative B regarding the number non-biogas engines that would be replaced with electric motors and because secondary CO2 emissions from construction equipment anticipated for these two alternatives are expected to be equivalent, both PAR 1110.2 and Alternative B are expected to generate similar CO2 emission reductions. Alternative D could potentially generate greater CO2 emissions reductions based on mandatory replacement of existing non-biogas ICEs with electric motors for those engine categories identified were compliance would be less costly than retrofitting existing engines. It is anticipated, however, that Alternative D would generate lower CO2 emission reductions than the proposed project, because it would implement a lower CO concentration requirement. Reducing CO emissions using an oxidation catalyst increases CO2 emissions.

The technology assessment required for PAR 1110.2 and all alternatives (except Alternative A) would verify the actual number of non-biogas engines replaced with electric motors and associated CO2 emission reductions. Any CO2 emission reduction shortfalls are expected to be made up through other CO2 emission reduction programs.

Hazards/Hazardous Materials

Neither Alternative A nor Alternative C would require the use of hazardous materials that could generate significant adverse hazard/hazardous materials impacts. The hazards analysis for PAR 1110.2 concluded significant adverse hazard impacts could occur at biogas facilities where operators retrofit existing equipment with SCR units or replace existing engines with LNG plants. For example, the toxic end point from aqueous ammonia would be 0.1 mile, which could expose receptors to ERPG 2 levels of ammonia, which is considered significant. Relative to LNG plants, the distance of a one psi shockwave from an LNG tank failure could be 0.2 mile. Adverse impacts from an accidental upset of an LNG truck could be up to 0.3 mile. Because receptors are expected to be located within these impact zones, this impact is considered to be significant. Because Alternatives B and D have the same requirements for biogas engines as PAR 1110.2, it is anticipated that hazard impacts under these alternatives would be equivalent to the proposed project. Similarly, the proposed project and Alternatives B and D may also generate significant adverse hazard impacts from the accidental upset of LNG transport trucks.

Solid/Hazardous Waste

Neither Alternative A nor Alternative C is expected to generate solid waste impacts. Alternative A imposes no additional requirements so no additional waste would be generated at affected facilities. Similarly, Alternative C does not contain any additional control requirements that would result in the generation of wastes. PAR 1110.2 and Alternatives B and D impose similar requirements that could generate additional wastes such as disposal of any existing emissions control equipment, catalyst, carbon, diesel fuel, etc. In spite of the potential for waste generation by PAR 1110.2 and Alternatives B and D, local or state landfills have the capacity to accommodate additional wastes produced by these proposals. Therefore, neither PAR 1110.2 nor any of the project alternatives have the potential to generate significant adverse solid/hazardous waste impacts.

CONCLUSION

Because Alternative A would impose no additional control or compliance requirements, with the exception of air quality, it would not be expected to generate significance adverse impacts. Air quality was concluded to be significant for this alternative because it would not necessarily eliminated or limit future exceedances of existing Rule 1110.2 emission control requirements. Further, Alternative A would not accomplish the two primary objectives of the proposed project, which are to reduce future violations of existing compliance requirements through enhanced enforcement and further reduce NOx, CO and VOC emissions from affected engines.

Alternative B would extend and increase the low-use exception to non-biogas engines and extend the 15 minute averaging time during compliance testing to one hour. Impacts from implementing Alternative B would generally be similar to PAR 1110.2 because the greatest impacts occur from the various compliance options for biogas engines. Compliance options are essentially the same for both Alternative B and PAR 1110.2. Alternative B may generate lower construction emissions overall compared to PAR 1110.2, but because major construction activities are anticipated to occur at biogas facilities the maximum daily construction emissions may not be different from those identified for PAR 1110.2. CO2 emission reductions would be similar to CO2 emission reductions identified for PAR 1110.2 because it is expected that replacing non-biogas ICEs with electric motors will be a less costly compliance option for the same categories of ICEs affected by both PAR 1110.2 and Alternative B. Aesthetic and hazards/hazardous material impacts are expected to be similar to PAR 1110.2 and, therefore, significant. Similarly, energy and solid/hazardous waste impacts are expected to be similar to PAR 1110.2 and, therefore, less than significant.

Alternative C would not impose any addition emission control requirements beyond what is currently required by existing Rule 1110.2. Alternative C would require additional CEMs, monitoring, testing, etc., to enhance enforcement of existing emission control requirements. Installation of CEMs, additional monitoring, etc., is not expected to change the visual character of the facility or surroundings and, therefore, would not be expected to generate significant adverse aesthetic impacts. Additional compliance requirements would not generate significant adverse construction or operational air quality impacts. Air toxics would be generated from source testing vehicle trips, but health risk from a single trip every other year would be negligible. Although Alternative C is not expected to achieve further emission reductions, it would not generate significant adverse air quality impacts. Adverse energy impacts from monitoring equipment and travel associated with additional source test are expected to be less than significant. Because Alternative C does not impose further emission control requirements, no facility operators would implement emission compliance options that could generate significant hazards/hazardous material impacts, because hazards would not be generated from increased monitoring and source testing. Alternative C would not generate significant solid or hazardous waste from monitoring or source testing. Therefore, Alternative C is not expected to create significant adverse impacts in any environmental topic areas.

Alternative D is expected to generate significant adverse environmental impacts similar to those identified for PAR 1110.2. Alternative D may incrementally increase adverse environmental impacts because larger or additional control may be required to meet the lower CO compliance concentration limits. CO2 emission reductions would occur through the mandatory replacement of non-biogas engines with electric motors for categories for categories of engines where this compliance option is less costly than complying with the emission control requirements. While in practice Alternative D could generate greater adverse environmental impacts, the assumptions applied to PAR 1110.2 would also apply to Alternative D because these assumptions provide the most conservative analysis possible. Therefore, for this analysis the adverse environmental impacts from PAR 1110.2 and Alternative D are equivalent. Alternative D would be expected to create significant adverse aesthetics, air quality, and hazards/hazardous waste. Like PAR 1110.2, Alternative D would not be expected to create significant adverse energy or solid/hazardous waste impacts

A comparison of the impacts from PAR 1110.2 and all project alternatives is presented in Table 5-28.

Pursuant to CEQA Guidelines §15126.6(e)(2), if the environmentally superior alternative is the no project alternative, the CEQA document shall also identify an environmentally superior alternative among the other alternatives. In the case of the alternatives to PAR

1110.2, the no project alternative is not considered to be the environmentally superior alternative. Alternative A – No Project Alternative, does not impose any additional requirements beyond those in existing Rule 1110.2 and as a result, does not generate any aesthetics, energy, hazards/hazardous materials, or solid/hazardous waste impacts. However, because Alternative A does not impose any compliance requirements to enhance enforcement, it would not necessarily prevent or limit future exceedances of the emission control requirements in existing Rule 1110.2. This is considered to be a significant adverse air quality impact. The only alternative that does not generate any significant adverse environmental impacts is Alternative C – Enhanced Enforcement, but it would not achieve the project objective of partially implementing 2007 AQMP Control Measure MCS-01 – Facility Modernization. While the proposed project is the staff's proposed project, the Governing Board may choose to adopt any of the alternatives in whole or in part in place of the proposed project, based on other considerations in addition to environmental concerns such as compliance costs, effects on future employment (jobs lost, for example), etc.

The *CEQA Guidelines §15126.6(e)(2)* requires the environmentally superior alternative to be identified. In addition, SCAQMD Environmental Justice Enhancement II-1 recommends that all SCAQMD CEQA assessments include a feasible project alternative with the lowest air toxics emissions. Excluding Alternative A, the No Project Alternative, Alternative C would be the environmentally superior and least toxic alternative, because it would not require additional controls which may have adverse toxic impacts and require additional vehicle trips, but it would not achieve the project objective of partially implementing 2007 AQMP Control Measure MCS-01 – Facility Modernization.

The proposed project is not the most environmentally superior project or lease toxic alternative (Alternative C is both). However, the proposed project would completely fulfill the project objective of further reducing NOx, CO and VOC emissions from ICEs and partially implementing 2007 AQMP Control Measure MCS-01 – Facility Modernization, which Alternatives A and C do not, and is qualitatively environmentally better than Alternative D. PAR 1110.2 is preferred to Alternative B, because it would achieve greater reductions with similar adverse environmental impacts. While the proposed project is the staff preferred alternative, the Governing Board may choose to adopt any of the alternatives in whole or in part in place of the proposed project, based on other considerations in addition to environmental concerns such as compliance costs, effects on future employment (jobs lost, for example), etc.

Table 5-28
Comparison of Adverse Environmental Impacts of the Alternatives

Environmental Topic	Proposed Project	Alternative A (No Project)	Alternative B (Low Use)	Alternative C (~~Compliance Only~~ Enhanced Compliance)	Alterative D (BACT)
Aesthetics	Significant	Not significant no Impact	Significant less than PAR 1110.2	Not significant	Significant Equivalent to PAR 1110.2
Air Quality					
Criteria	Significant	Significant, greater than PAR 1110.2	Significant Equivalent to PAR 1110.2	Not significant, less than PAR 1110.2	Significant Equivalent to PAR 1110.2
Toxic	Significant	Not significant, less than PAR 1110.2	~~Not s~~Significant, same as PAR 1110.2	Not significant, less than PAR 1110.2	~~Not s~~Significant, same as PAR 1110.2
Greenhouse Gas	Not significant beneficial effect	Not significant no beneficial effect	Not significant equivalent to PAR 1110.2	Not significant no beneficial effect	Not significant less than PAR 1110.2
Energy					
Electricity	Not significant	Not significant no Impact	Not significant, same as PAR 1110.2	Not significant, less than PAR 1110.2	Not significant Equivalent to PAR 1110.2
Natural Gas	Not significant beneficial effect	Not significant less than PAR 1110.2	Not significant Equivalent to PAR 1110.2	Not significant, less than PAR 1110.2	Not significant Equivalent to PAR 1110.2
Diesel	Not significant	Not significant no Impact	Not significant, less than PAR 1110.2	Not significant, less than PAR 1110.2	Not significant Equivalent to PAR 1110.2
Hazards/Hazardous Material	Significant	Not significant no Impact	Significant, same as PAR 1110.2	Not significant, less than PAR 1110.2	Significant Equivalent to PAR 1110.2
Solid/Hazardous Waste	Not significant	Not significant no Impact	Not significant, same as PAR 1110.2	Not significant, same as PAR 1110.2	Not significant Equivalent to PAR 1110.2

A P P E N D I X A (of the ~~Draft~~Final EA)

A B B R E V I A T I O N S A N D A C R O N Y M N S

Table of Acronyms and Abbreviations

Acronym/Abbreviation	Description
ACWA	Association of California Water Agencies
AFRC	Air-to-fuel ratio controller
AQMP	Air quality management plan
ASME	American Society Of Mechanical Engineers
ATCM	Airborne Toxic Control Measures
BACT	Best Available Control Technology
BARCT	Best available retrofit control technology
bph	Brake horsepower
BTU	British thermal unit
CARB	California Air Resources Board
Catox	Catalytic oxidation
CEMS	Continuous emission monitoring system
CEQA	California Environmental Quality Act
CI	Compression-ignition
CNG	Compressed natural gas
CO	Carbon monoxide
dBA	Decibels
EA	Environmental Assessment
EEF	electrical energy factor
EGR	Exhaust gas recirculation
ERPG	Emergency Response Planning Guideline
FY	Fiscal year
g	Gram
HHV	High heating value
I&M	Inspection and monitoring
ICE	Internal combustion engine
in	Inches
IS	Initial Study
k	Kilo
kW	Kilowatt
L	Concentration limit
LA DWP	Los Angeles Department of Water and Power
lb	Pound

Table of Acronyms and Abbreviations (continued)

Acronym/Abbreviation	Description
LPG	liquefied petroleum gas
m	Meter
MDAB	Mojave Desert Air Basin
μg	Micrograms
MM	Million
MMBtu	Million British thermal units
MMSCF	Million standard cubic feet
MTA	Los Angeles Metropolitan Transportation Agency
MWD	Metropolitan Water District
MW_e	Electrical megawatt-hours
MW_{th}-hours	Thermal megawatt-hours
NG	natural gas
NMHC	Non-methane hydrocarbon
NOx	Oxides of nitrogen
NSCR	Non-selective catalytic reduction
NSPS	New Source Performance Standards
O2	Oxygen
OSHA	Occupational Safety and Health Administration
Ox Cat	Catalytic oxidation
PAR	Proposed amended rule
PERP	Portable Equipment Registration Program
PM	Particulate matter
PM10	Particulate matter less than 10 microns in diameter
PM2.5	Particulate matter less than 2.5microns in diameter
ppm	Parts per million
ppmdv	Parts per million, dry volume
ppmv	Parts per million by volume
PSC	Pre-stratified charge
R	Ratio
RACT	Retrofit available control technology
RECLAIM	Regional CLean Air Incentives Market
RICE	Reciprocating Internal Combustion Engines
ROG	Reactive organic gas

Table of Acronyms and Abbreviations (continued)

Acronym/Abbreviation	Description
SCAB	South Coast Air Basin
SCAQMD	South Coast Air Quality Management District
scf	Standard cubic feet
SCR	Selective catalytic reduction
SI	Spark-ignited
SSAB	Salton Sea Air Basin
TAC	Toxic Air Contaminant
TWC	Three-way catalyst
VOC	Volatile organic compound
W	Watt
WD	Water District
wt	Weight

A P P E N D I X   B (of the ~~Draft~~Final EA)

P R O P O S E D   A M E N D E D   R U L E   1 1 1 0 . 2

(Adopted August 3, 1990)(Amended September 7, 1990)(Amended August 12, 1994)
(Amended December 9, 1994)(Amended November 14, 1997)
(Amended June 3, 2005)(Proposed Amendments December 14, 2007)

PROPOSED AMENDED RULE 1110.2 EMISSIONS FROM GASEOUS- AND LIQUID-FUELED ENGINES

(a) Purpose

The purpose of Rule 1110.2 is to reduce Oxides of Nitrogen (NO_x), Volatile Organic Compounds (VOCs), and Carbon Monoxide (CO) from engines.

(b) Applicability

All stationary and portable engines over 50 rated brake horsepower (bhp) are subject to this rule.

(c) Definitions

For the purpose of this rule, the following definitions shall apply:

(1) AGRICULTURAL STATIONARY ENGINE is a non-portable engine used for the growing and harvesting of crops or the raising of fowl or animals for the primary purpose of making a profit, providing a livelihood, or conducting agricultural research or instruction by an educational institution. An engine used for the processing or distribution of crops or fowl or animals is not an agricultural engine.

(2) APPROVED EMISSION CONTROL PLAN is a control plan, submitted on or before December 31, 1992, and approved by the Executive Officer prior to November 14, 1997, ~~describing all actions and alternatives, including a schedule of increments of progress to meet or exceed the requirements or applicable emissions limitations in paragraph (d)(1)~~that was required by subdivision (d) of this rule as amended September 7, 1990.

(3) CERTIFIED SPARK-IGNITION ENGINES mean engines certified by California Air Resources Board (CARB) to meet emission standards in accordance with Title 13, Chapter 9, Article 4.5 of the California Code of Regulations (CCR).

(4) EMERGENCY STANDBY ENGINE is an engine which operates as a temporary replacement for primary mechanical or electrical power during

periods of fuel or energy shortage or while the primary power supply is under repair.

(5) ENGINE is any spark- or compression-ignited internal combustion engine, including engines used for control of VOCs, but not including engines used for self-propulsion.

(6) EXEMPT COMPOUNDS are defined in District Rule 102 - Definition of Terms.

(7) FACILITY means any source or group of sources or other air contaminant emitting activities which are located on one or more contiguous properties within the District, in actual physical contact or separated solely by a public roadway or other public right-of-way, and are owned or operated by the same person (or by persons under common control), or an outer continental shelf (OCS) source as determined in Section 55.2 of Title 40, Part 55 of the Code of Federal Regulations (40 CFR Part 55). Such above-described groups, if noncontiguous, but connected only by land carrying a pipeline, shall not be considered one facility. Sources or installations involved in crude oil and gas production in Southern California Coastal or OCS Waters and transport of such crude oil and gas in Southern California Coastal or OCS Waters shall be included in the same facility which is under the same ownership or use entitlement as the crude oil and gas production facility on-shore.

(8) LEAN-BURN ENGINE means an engine that operates with high levels of excess air and an exhaust oxygen concentration of greater than 4 percent.

(9~~8~~) LOCATION means any single site at a building, structure, facility, or installation. For the purpose of this definition, a site is a space occupied or to be occupied by an engine. For engines which are brought to a facility to perform maintenance on equipment at its permanent or ordinary location, each maintenance site shall be a separate location.

(10) NET ELECTRICAL ENERGY means the electrical energy produced by a generator, less the electrical energy consumed by any auxiliary equipment necessary to operate the engine generator and, if applicable, any heat recovery equipment, such as heat exchangers.

(11~~9~~) NON-ROAD ENGINE is any engine, defined under 40 CFR Part 89, that does not remain or will not remain at a location for more than 12 consecutive months, or a shorter period of time where such period is representative of normal annual source operation at a stationary source that resides at a fixed location for more than 12 months (e.g., seasonal operations such as canning facilities), and meets one of the following:

(A) Is used in or on a piece of equipment that is self-propelled or serves a dual purpose by both propelling itself and performing another function (such as a mobile crane); or

(B) Is used in or on a piece of equipment that is intended to be propelled while performing its function (such as lawn mowers and string trimmers); or

(C) By itself, or in or on a piece of equipment, is portable or transportable, meaning designed to be and capable of being carried or moved from one location to another. Transportability includes, but is not limited to, wheels, skids, carrying handles, dolly, trailer, platform or mounting.

(12) OPERATING CYCLE means a period of time within which a round of regularly recurring events is completed, and cannot be stopped without the risk of endangering public safety or health, causing material damage to the equipment or product, or cannot be stopped due to technical constraints. Economic reasons alone will not be sufficient to extend this time period. The operating cycle includes batch processes that may start and finish several times within a twenty-four hour period, in which case each start to finish interval is considered a complete cycle.

(13) OXIDES OF NITROGEN (NOx) means nitric oxide and nitrogen dioxide.

(14~~0~~) PORTABLE ENGINE is an engine that, by itself or in or on a piece of equipment, is designed to be and capable of being carried or moved from one location to another. Indications of portability include, but are not limited to, wheels, skids, carrying handles, dolly, trailer, platform or mounting. The operator must demonstrate the necessity of the engine being periodically moved from one location to another because of the nature of the operation.

An engine is not portable if:

(A) the engine or its replacement remains or will reside at the same location for more than 12 consecutive months. Any engine, such as a back-up or stand-by engine, that replaces an engine at a location and is intended to perform the same function as the engine being replaced, will be included in calculating the consecutive time period. In that case, the cumulative time of both engines, including the time between the removal of the original engine and installation of the replacement engine, will be counted toward the consecutive time period; or

(B) the engine remains or will reside at a location for less than 12 consecutive months where such a period represents the full length of normal annual source operations such as a seasonal source; or

(C) the engine is removed from one location for a period and then it or its equivalent is returned to the same location thereby circumventing the portable engine residence time requirements.

The period during which the engine is maintained at a designated storage facility shall be excluded from the residency time determination.

(15~~1~~) RATED BRAKE HORSEPOWER (bhp) is the rating specified by the manufacturer, without regard to any derating, and listed on the engine nameplate.

(16) RICH-BURN ENGINE WITH A THREE-WAY CATALYST means an engine designed to operate near stoichiometric conditions with a catalytic control device that simultaneously reduces emissions of NOx, CO and VOC.

(17~~2~~) STATIONARY ENGINE is an engine which is either attached to a foundation or if not so attached, does not meet the definition of a portable or non-road engine and is not a motor vehicle as defined in Section 415 of the California Vehicle Code.

(18~~3~~) TIER 2 AND TIER 3 DIESEL ENGINES mean engines certified by CARB to meet Tier 2 or Tier 3 emission standards in accordance with Title 13, Chapter 9, Article 4 of the CCR.

(19) USEFUL HEAT RECOVERED means the waste heat recovered from the engine exhaust and/or cooling system that is put to productive use. The waste heat recovered may by assumed to be 100% useful unless the hot water, steam or other medium is vented to the atmosphere, or sent directly to a cooling tower or other unproductive use.

(20~~14~~) VOLATILE ORGANIC COMPOUND (VOC) is as defined in Rule 102.

(d) Requirements

(1) Stationary Engines~~ Emission Limits~~:

(A) Operators of stationary engines with an amended Rule 1110.1 Emission Control Plan submitted by July 1, 1991, or an Approved Emission Control Plan, designating the permanent removal of engines or the replacement of engines with electric motors, in accordance with subparagraph (d)(1)(B), shall do so by December 31, 1999, or not operate the engines on or after December 31, 1999 in a manner that exceeds the emission concentration limits listed in Table I:

TABLE I ALTERNATIVE TO ELECTRIFICATION CONCENTRATION LIMITS		
NO_x	VOC	CO
(ppmvd)[1] 11	(ppmvd)~~1,~~ [2] 30	(ppmvd)[1] 70

[1] Parts per million by volume, c~~C~~orrected to 15% oxygen on a dry basis and averaged over 15 minutes.

[2] Parts per million by volume, m~~M~~easured as carbon, corrected to 15% oxygen on a dry basis and averaged over the sampling time required by the test method.

(B) The operator of any other stationary engine subject to this rule shall

(i) Remove such engine permanently from service or replace the engine with an electric motor, or

(ii) Not operate the engine in a manner that exceeds the emission concentration limits listed in Table~~ABLE~~ II.

TABLE II CONCENTRATION LIMITS		
NO_x (ppmvd)[1]	VOC (ppmvd)[2]	CO (ppmvd)[1]
~~(ppm)~~~~1~~ bhp ≥ 500: 36 bhp < 500: 45	~~(ppm)~~~~1, 2~~ 250	~~(ppm)~~~~1~~ 2000
CONCENTRATION LIMITS EFFECTIVE JULY 1, 2010		

NO_x (ppmvd)[1]	VOC (ppmvd)[2]	CO (ppmvd)[1]
bhp ≥ 500: 11 bhp < 500: 45	bhp ≥ 500: 30 bhp < 500: 250	bhp ≥ 500: 250 bhp < 500: 2000
CONCENTRATION LIMITS EFFECTIVE JULY 1, 2011		
NO_x (ppmvd)[1]	VOC (ppmvd)[2]	CO (ppmvd)[1]
11	30	250

1 Parts per million by volume, c~~C~~orrected to 15% oxygen on a dry basis and averaged over 15 minutes.

2 Parts per million by volume, m~~M~~easured as carbon, corrected to 15% oxygen on a dry basis and averaged over the sampling time required by the test method.

The concentration limits effective on and after July 1, 2010 shall not apply to engines that operate less than 500 hours per year or use less than 1 x 10^9 British Thermal Units (Btus) per year (higher heating value) of fuel.

If the operator of a two-stroke engine equipped with an oxidation catalyst and insulated exhaust ducts and catalyst housing demonstrates that the CO and VOC limits effective on and after July 1, 2010 are not achievable, then the Executive Officer may, with United States Environmental Protection Agency (EPA) approval, establish technologically achievable, case-by-case CO and VOC limits in place of the concentration limits effective on and after July 1, 2010. The case-by-case limits shall not exceed 250 ppmvd VOC and 2000 ppmvd CO.

If the operator of an engine that uses non-pipeline quality natural gas demonstrates that due to the varying heating value of the gas a longer averaging time is necessary, the Executive Officer may establish for the engine a longer averaging time, not to exceed six hours, for any of the concentration limits of Table II. Non-pipeline quality natural gas is a gas that does not meet the gas specifications of the local gas utility and is not supplied to the local gas utility.

(C) Notwithstanding the provisions in subparagraph (d)(1)(B), the operator of any stationary engine fired by ~~90% or more of~~ landfill or digestor gas (biogas)~~, based on the monthly heat input (higher heating value) of the fuels,~~ ~~described in Table III~~ shall not operate the engine in a manner that exceeds ~~an~~the emission concentration limits of Table III, provided that the facility monthly average biogas useage by the biogas engines is 90% or more, based on the higher heating value of the fuels used. The calculation of the monthly facility biogas use percentage may exclude natural gas fired during: any electrical outage at the facility; a Stage 2 or higher electrical emergencies called by the California Independent System Operator Corporation; and when a sewage treatment plant activates an Emergency Operations Center or Incident Command System, as part of an emergency response plan, because of either high influent flows caused by precipitation or a disaster. ~~2000 ppm by volume of CO corrected to 15 percent oxygen on a dry basis and averaged over 15 minutes, or the emission concentration limits for VOC as carbon or NOx specified by the following formula:~~

The concentration limits effective on and after July 1, 2012 shall become effective provided the Executive Officer conducts a technology assessment that confirms that the limits are achievable, and reports to the Governing Board by July 2010, at a regularly scheduled public meeting.

The concentration limits effective on and after July 1, 2012 shall not apply to engines that operate less than 500 hours per year or use less than 1×10^9 Btus per year (higher heating value) of fuel.

TABLE III

CONCENTRATION LIMITS FOR LANDFILL AND DIGESTOR GAS-FIRED ENGINES

NO_x (ppmvd)[1]	VOC (ppmvd)[2]	CO (ppmvd)[1]
bhp ≥ 500: 36 x ECF[3] bhp < 500: 45 x ECF[3]	Landfill Gas: 40 Digestor Gas: 250 x ECF[3]	2000

CONCENTRATION LIMITS EFFECTIVE JULY 1, 2012		
NO_x (ppmvd)[1]	VOC (ppmvd)[2]	CO (ppmvd)[1]
11	30	250

[1] Parts per million by volume, corrected to 15% oxygen on a dry basis and averaged over 15 minutes.

[2] Parts per million by volume, measured as carbon, corrected to 15% oxygen on a dry basis and averaged over the sampling time required by the test method.

[3] ECF is the efficiency correction factor.

The ECF shall be 1.0 unless:

(i) The engine operator has measured the engine's net specific energy consumption (q_a), in compliance with ASME Performance Test Code PTC 17 -1973, at the average load of the engine; and

(ii) The ECF-corrected emission limit is made a condition of the engine's permit to operate.

The ECF is as follows:

$$ECF = \frac{9250 \text{ Btus/hp-hr}}{\text{Measured } q_a \text{ in Btus/hp-hr}}$$

Measured q_a shall be based on the lower heating value of the fuel. ECF shall not be less than 1.0.

The Executive officer may approve the burning of more than 10% natural gas in a landfill or digestor gas-fired engine, when it is necessary, if: the only alternative to limiting natural gas to 10% would be shutting down the engine and flaring more landfill or digestor gas; or the engine requires more natural gas in order for a waste heat recovery boiler to provide enough thermal energy to operate a sewage treatment plant, and other boilers at the facility are unable to provide the necessary thermal energy.

Once an engine complies with concentration limits effective on and after July 1, 2012, there shall be no limit on the percentage of natural gas burned.

~~CONCENTRATION LIMIT FORMULA~~				
~~Concentration Limit~~	~~=~~	~~Reference Limit~~	~~x~~	~~EFF~~ / ~~25%~~

~~Where:~~

~~Concentration Limit~~ = ~~the allowable NO_x, or VOC emission limit (ppm by volume) corrected to 15 percent oxygen on a dry basis, and averaged over 15 consecutive minutes.~~

~~Reference Limit~~ = ~~the NO_x or VOC emission limit (ppm by volume) corrected to 15 percent oxygen on a dry basis. The reference limits for various bhp ratings (continuous rating by the manufacturer) are listed in TABLE IV.~~

~~TABLE III~~ ~~STATIONARY ENGINES DESCRIPTION~~
~~For electric power generation~~
~~Fired by landfill gas~~
~~Fired by sewage digester gas~~
~~Used to drive a water supply or conveyance pump except for aeration facilities~~
~~Fired by oil field-produced gas~~
~~For integral engine-compressor applications operating less than 4000 hours per calendar year~~
~~Fired by liquefied petroleum gas (LPG)~~

~~TABLE IV~~ ~~REFERENCE LIMITS, ppm~~		
~~Bhp Rating~~	~~NO_x~~	~~VOC~~

~~500 and greater~~	~~36~~	~~250~~
~~Greater Than 50 and Less Than 500~~	~~45~~	~~250~~

~~And,~~

~~EFF~~ = ~~the demonstrated percent efficiency at full load when averaged over 15 consecutive minutes of the engine only without consideration of any downstream energy recovery from the actual heat rate, in Btu/kW-hr, corrected to the HHV (higher heating value) of the fuel; or the manufacturer's continuous rated percent efficiency (manufacturer's rated efficiency) of the engine after correction from LHV (lower heating value) to the HHV of the fuel, whichever efficiency is higher. The value of EFF shall not be less than 25 percent. Engines with lower efficiencies will be assigned a 25 percent efficiency for this calculation.~~

$$\cancel{EFF = \frac{3413 \times 100\%}{\text{Actual Heat Rate at HHV of Fuel (Btu/kW-hr)}}}$$

~~or~~

$$\cancel{EFF = \text{(Manufacturer's Rated Efficiency at LHV)} \times \frac{LHV}{HHV}}$$

(D) The operator of any new engine subject to subparagraph (e)(1~~2~~)(B) shall:

(i) Comply with the requirements of Best Available Control Technology in accordance with Regulation XIII if the engine requires a District permit; or

(ii) Not operate the engine in a manner that exceeds the emission concentration limits in Table~~ABLE~~ I if the engine does not require a District permit.

(E) By (one year from date of rule adoption), the operator of a spark-ignited engine without a Rule 218-approved continuous emission monitoring system (CEMS) or a Regulation XX (RECLAIM)-approved CEMS shall equip and maintain the engine with an air-to-fuel ratio controller with an oxygen sensor and feedback control, or other equivalent technology approved by the Executive Officer, ~~CARB and EPA.~~

(F) New Non-Emergency Electrical Generators

(i) All new non-emergency engines driving electrical-generators shall comply with the following emission standards, based on the emission standards of the Distributed Generation Certification Program, Article 3, Subchapter 8, Chapter 1, Division 30, Title 17 of the California Code of Regulations, that became effective on January 1, 2007:

TABLE IV

EMISSION STANDARDS FOR NEW ELECTRICAL GENERATION ENGINES

Pollutant	Emission Standard (lbs/MW-hr)[1]
NOx	0.070
CO	0.2~~1~~0
VOC	0.10~~02~~[2]

1. The averaging time of the emission standards is 15 minutes for NOx and CO and the sampling time required by the test method for VOC, except as described in the following clause.
2. Mass emissions of VOC shall be calculated using a ratio of 16.04 pounds of VOC per lb-mole of carbon.

(ii) Engines subject to this subparagraph that produce combined heat and electrical power may include one megawatt-hour (MW-hr)-for each 3.4 million Btus of useful heat recovered (MW_{th}-hr), in addition to each MW-hr of net electricity produced (MW_e-hr). The compliance of such engines shall be based on the following equation:

Lbs = Lbsx Electrical Energy Factor (EEF)
MW-hr MW_e-hr

Where:

Lbs/MW-hr = The calculated emissions that shall comply with the emission standards in Table IV

Lbs/MW_e-hr = The short-term engine emission limit in pounds per MW_e-hr of net electrical energy produced, averaged over 15 minutes. The engine shall comply with this limit at all times.

EEF = The annual MW_e-hrs of net electrical energy produced divided by the sum of annual MW_e-hrs plus annual MW_{th}-hrs of useful heat recovered. The engine operator shall demonstrate annually that the EEF is less than the value required for compliance.

(iii) For combined heat and power engines, the short-term emission limits in lbs/MW_e-hr and the maximum allowed annual EEF must be selected by operator and stated on the operating permit.

(iv) Notwithstanding Rule 2001, the requirements of this subparagraph shall apply to NOx emissions from new non-emergency engines driving electrical-generators subject to Regulation XX (RECLAIM).

(v) This subparagraph does not apply to: engines installed prior to (date of adoption); engines issued a permit to construct prior to (date of adoption) and installed within 12 months of the date of the permit to construct; engines for which an application is deemed complete by October 1, 2007; engines installed by an electric utility on Santa Catalina Island; engines installed at remote locations without access to natural gas and electric power; engines used to supply electrical power to ocean-going vessels while at berth, prior to January 1, 2014; or landfill or digestor gas-fired engines that meet the requirements of subparagraph (d)(1)(C).

(2) Portable Engines:

~~(A) The operator of any portable engine subject to this rule shall:~~

~~(i) By December 31, 1999, not operate the engine in a manner that exceeds the emission concentration limits of TABLE V for spark-ignition engines, or the emission requirements of TABLE VI for compression-ignition engines;~~

~~(ii) By January 1, 2010, meet the most stringent emissions standard which is the applicable emissions standard in effect and set forth in Title 13 of the CCR for that engine rating. If no emissions standard exists under the CCR, then the applicable emissions standard set forth in 40 CFR Part 89 shall apply. If no standard exists under the CCR and 40 CFR Part 89, then the applicable requirements of TABLE V for spark-ignition engines or TABLE VI for compression-ignition engines shall apply; and~~

~~(iii) Submit to the Executive Officer a letter certifying that the engine is in compliance with the provisions of the subparagraph, in accordance with the compliance schedule in paragraph (e)(2).~~

~~**TABLE V**~~ ~~PORTABLE SPARK-IGNITION ENGINE CONCENTRATION LIMITS~~		
~~NO_x~~	~~VOC~~	~~CO~~
~~80 ppm[3] (1.5 g/bhp-hr)~~	~~240 ppm[3] (1.5 g/bhp-hr)~~	~~176 ppm[3] (2.0 g/bhp-hr)~~

~~[3] Corrected to 15% oxygen on a dry basis and averaged over 15 minutes.~~

~~**TABLE VI**~~ ~~**PORTABLE COMPRESSION-IGNITION ENGINE EMISSION REQUIREMENTS**~~	
~~Rated Brake Horsepower~~	~~Requirements~~

~~Greater Than 50 And Less Than 117~~	~~770 ppm[4] NO_x (10.0 g/bhp-hr), or turbocharger and 4-degree injection timing retard~~
~~Greater Than or Equal To 117 And Less Than 400~~	~~550 ppm[4] NO_x (7.2 g/bhp-hr), or turbocharger and aftercooler/intercooler and 4-degree injection timing retard~~
~~Greater Than or Equal To 400~~	~~535 ppm[4] NO_x (7.0 g/bhp-hr), or turbocharger and aftercooler/intercooler and 4-degree injection timing retard~~
~~[4] Corrected to 15% oxygen on a dry basis and averaged over 15 minutes.~~	

(A~~B~~) The operator of any portable engine generator subject to this rule shall not use the portable generator for:

(i) Power production into the electric grid, except to maintain grid stability during an emergency event or other unforeseen event that affects grid stability; or

(ii) Primary or supplemental power to a building, facility, stationary source, or stationary equipment, except during unforeseen interruptions of electrical power from the serving utility, maintenance and repair operations, and remote operations where grid power is unavailable. For interruptions of electrical power, the operation of a portable generator shall not exceed the time of the actual interruption of power.

This subparagraph shall not apply to a portable generator that complies with emission concentration limits of Table I and the other requirements in this rule applicable to stationary engines.

(B) The operator of any portable diesel engine shall comply with the applicable requirements of the Subchapter 7.5 Airborne Toxic Control Measures for diesel particulate matter in Chapter 1, Division 3, Title 17 of the California Code of Regulations.

(C) The operator of any portable spark-ignited engine shall comply with the applicable requirements of the Large Spark Ignition Engine Fleet Requirements, Article 2, Chapter 15, Division 3, Title 13 of the California Code of Regulations.

(e) Compliance

~~(1) Portable Engines:~~

~~The owner/operator of portable engines subject to the provisions of subparagraph (d)(2) shall:~~

~~(A) For engines for which engine modification or add-on control is used to comply with the applicable requirements of TABLE V for spark-ignition engines, or TABLE VI for compression-ignition engines:~~

~~(i) By April 30, 1998, submit applications for permit to construct and permit to operate engines;~~

~~(ii) By September 30, 1999, initiate engine modification or control equipment installation; and~~

~~(iii) By December 31, 1999, have engines in compliance with the applicable requirements of TABLE V for spark-ignition engines, or TABLE VI for compression-ignition engines.~~

~~(B) For engines for which engine modification or add-on control is used to comply with the most stringent emissions standard as set forth in clause (d)(2)(A)(ii):~~

~~(i) By April 30, 2008, submit applications for permit to construct and permit to operate engines;~~

~~(ii) By September 30, 2009, initiate engine modification or control equipment installation; and~~

~~(iii) By December 31, 2009, have engines in compliance with the most stringent emissions standard.~~

~~(C) By December 31, 2009, if the engines are in compliance with the most stringent emissions standard, submit to the Executive Officer a letter certifying that the engines are in compliance with the emissions standard.~~

(1~~2~~) Agricultural Stationary Engines:

(A) The operator of any agricultural stationary engine subject to this rule and installed or issued a permit to construct prior to June 3, 2005 shall comply with paragraph (d)(1)(B) and the other applicable provisions of this rule in accordance with the compliance schedules in Table V~~I~~:

TABLE~~able~~ V~~I~~ **COMPLIANCE SCHEDULES FOR STATIONARY AGRICULTURAL ENGINES**		
Action Required	**Tier 2 and Tier 3 Diesel Engines, Certified Spark-Ignition Engines, and All Engines at Facilities with Actual Emissions Less Than the Amounts in the Table of Rule 219(q~~e~~)**	**Other Engines**
Submit notification of applicability to the Executive Officer	January 1, 2006	January 1, 2006
Submit to the Executive Officer applications for permits to construct engine modifications, control equipment, or replacement engines	March 1, 2009	September 1, 2007
Initiate construction of engine modifications, control equipment, or replacement engines	September 30, 2009, or 30 days after the permit to construct is issued, whichever is later	March 30, 2008, or 30 days after the permit to construct is issued, whichever is later
Complete construction and comply with applicable requirements	January 1, 2010, or 60 days after the permit to construct is issued, whichever is later	July 1, 2008, or 60 days after the permit to construct is issued, whichever is later
Complete initial source testing	March 1, 2010, or 120 days after the permit to construct is issued, whichever is later	September 1, 2008, or 120 days after the permit to construct is issued, whichever is later

The notification of applicability shall include the following for each engine:

(i) Name and mailing address of the operator.

(ii) Address of the engine location.

(iii) Manufacturer, model, serial number, and date of manufacture of the engine.

(iv) Application number

(v) Engine type (diesel, rich-burn spark-ignition or lean-burn spark-ignition)

(vi) Engine fuel type

(vii) Engine use (pump, compressor, generator, or other)

(viii) Expected means of compliance (engine replacement, control equipment installation, or electrification)

(B) The operator of any new agricultural stationary engine that is not subject to the compliance schedule of subparagraph (e)(1~~2~~)(A) for existing engines shall comply with the requirements of subparagraph (d)(1)(D) immediately upon installation.

~~(3) Agricultural Portable Engines:~~

~~(A) The operator of any agricultural portable engine subject to this rule shall comply with paragraph (f)(2) by January 1, 2006.~~

(2) Non-Agricultural Stationary Engines:

(A) The operator of any stationary engine not meeting the requirements of subparagraphs (d)(1)(B) or (d)(1)(C) that go into effect in 2010 or later, shall comply with the compliance schedule in Table VI:

TABLE VI
COMPLIANCE SCHEDULE FOR NON -AGRICULTURAL STATIONARY ENGINES

Action Required	**Applicable Compliance Date**
Submit to the Executive Officer applications for permits to construct engine modifications, control equipment, or replacement engines	Twelve months before the final compliance date
Initiate construction of engine modifications, control equipment, or replacement engines	Three months before the final compliance date, or 60 days after the permit to construct is issued, whichever is later
Complete construction and comply with applicable requirements	The final compliance date, or 120 days after the permit to construct is issued, whichever is later

Complete initial source testing	60 days after the final compliance date in (d)(1)(B) or (d)(1)(C), or 180 days after the permit to construct is issued, whichever is later

(B) The operator of any stationary engine that elects to amend a permit to operate to incorporate ECF-adjusted emission limits shall submit to the Executive Officer an application for a change of permit conditions by (six months from date of adoption), and comply with emission limits of the previous version of this rule until (one year from date of adoption) when the engine shall be in compliance with the emission limits of this rule.

(C) The operator of any stationary engine that is required to add operating restrictions to a permit to operate to meet the requirements of paragraph (h)(2), shall submit to the Executive Officer an application for a change of permit conditions by (six months from date of adoption).

(3) Stationary Engine CEMS

(A) The operator of any stationary engine with an existing CEMS shall commence the reporting required by Rule 218 Subdivision (f) on January 1, 2008. The first summary report for the six months ending June 30, 2008 shall be due on July 30, 2008.

(B) The operator of any stationary engine that is required to modify an existing CEMS or install a CEMS on an existing engine, shall comply with the compliance schedule in Table VII. Public agencies shall be allowed one year more than the dates in Table VII, except for biogas engines.

TABLE VII
COMPLIANCE SCHEDULE NEW OR MODIFIED CEMS ON EXISTING ENGINES

	Applicable Compliance Dates For:		
Action Required	**Non-Biogas Engines Rated at 750 bhp or More**	**Non-Biogas Engines Rated at Less than 750 bhp**	**Biogas Engines***

Submit to the Executive Officer applications for new or modified CEMS	(six months from date of adoption)	(18 months from date of adoption)	January 1, 2011
Complete installation and commence CEMS operation, calibration, and reporting requirements.	Within 180 days of initial approval	Within 180 days of initial approval	Within 180 days of initial approval
Complete certification tests	Within 90 days of installation	Within 90 days of installation	Within 90 days of installation
Submit certification reports to Executive Officer	Within 45 days after tests are completed	Within 45 days after tests are completed	Within 45 days after tests are completed
Obtain final approval of CEMS	Within 1 year of initial approval	Within 1 year of initial approval	Within 1 year of initial approval

* A biogas engine is one that is subject to the emission limits of Table III.

(4) Stationary Engine Inspection and Monitoring (I&M) Plans:

The operator of stationary engines subject to the I&M plan provisions of subparagraph (f)(1)(D) shall:

(A) By (six months from date of adoption), submit an initial I&M plan application to the Executive Officer for approval;

(B) By (ten months from date of adoption), implement an approved I&M plan or the I&M plan as submitted if the plan is not yet approved.

Any operator of 15 or more stationary engines subject to the I&M plan provisions shall comply with the above schedule for at least 50% of engines, and for the remaining engines shall~~may, for up to 50 percent of the engines~~:

(C) By (12 months from date of adoption), submit an initial I&M plan application to the Executive Officer for approval;

(D) By (16 months from date of adoption), implement an approved I&M plan or the I&M plan as submitted if the plan is not yet approved.

(5) Stationary Engine Air-to-Fuel Ratio Controllers

(A) The operator of any stationary engine that does not have an air-to-fuel ratio controller, as required by subparagraph (d)(1)(E), shall comply with those requirements in accordance with the compliance schedule in Table VI, except that the application due date is no later than (three months from date of adoption) and the initial source testing may be conducted at the time of the ~~bi-annual~~ testing required by subparagraph (f)(1)(C).

~~(A)~~(B) The operator of any stationary engine that has the air-to-fuel ratio controller required by subparagraph (d)(1)(E), but it is not listed on the permit to operate, shall submit to the Executive Officer an application to amend the permit by (three months from date of adoption).

(C) The operator of more than five engines that do not have air-to-fuel ratio controllers may take an additional three months, to (15 months from rule adoption), to install the equipment on up to 50% of the affected engines.

(6) New Stationary Engines

The operator of any new stationary engine issued a permit to construct after (date of adoption) shall comply with the applicable I&M or CEMS requirements of this rule when operation commences. If applicable, the operator shall provide the required information in subparagraph (f)(1)(D) to the Executive Officer prior to the issuance of the permit to construct so that the I&M procedures can be included in the permit. A separate I&M plan application is not required.

(7) Biogas Engines

For any biogas engine for which the operator applies to the Executive Officer by (two months from date of adoption) for a change of permit conditions for ECF-corrected emission limits, or the approval to burn more than 10 percent natural gas in accordance with subparagraph (d)(1)(C), the biogas engine shall not be subject to the initial concentration limits of Tables II or III until six months from (date of adoption), provided the operator continues to comply with all emission limits in effect prior to (date of adoption).

~~(7)~~(8) Compliance Schedule Exception

If an engine operator submits to the Executive Officer an application for an administrative change of permit conditions to add a permit condition that causes the engine permit to expire by the effective date of any requirement of this rule, then the operator is not required to comply with the earlier steps required by this subdivision for that requirement. The effective date for the CEMS requirements shall be one year after the date that a CEMS application is due.

(f) Monitoring, Testing, ~~and~~ Recordkeeping and Reporting

(1) Stationary engines:

The operator of any engine subject to the provisions of paragraph (d)(1) of this rule shall meet the following requirements:

(A) Continuous Emission Monitoring

(i) For engines of 1000 bhp and greater~~,~~ and operating more than two million bhp-hr per calendar year, ~~install, operate and maintain in calibration~~ a NO_x and CO continuous emission monitoring system (CEMS) shall be installed, operated and maintained in calibration to demonstrate compliance with the emission limits of this rule. ~~CEMS shall meet the requirements described in 40 CFR Part 60, particularly those in Appendix B, Spec. 2 and Appendix F, as well as the reporting requirements of 40 CFR Part 60 Sections 60.7(c), 60.7(d), and 60.13, and shall include equipment that measures and records NO_x exhaust gas concentrations, corrected to 15 percent oxygen on a dry basis.~~

(ii) (I) For facilities with engines subject to paragraph (d)(1), having a combined rating of 1500 bhp or greater at the same location, and having a combined fuel usage of more than 16 x 10^9 Btus per year (higher heating value), CEMS shall be installed, operated and maintained in calibration to demonstrate compliance of those engines with the applicable NO_x and CO emission limits of this rule.

(II) Any engine that as of October 1, 2007 is located within 75 feet of another engine (measured from engine block to engine block) is considered to be at the same location. Operators of new engines shall not install engines farther than 75 feet from another engine unless the operator demonstrates to the

Executive Officer that operational needs or space limitations require it.

(III) The following engines shall not be counted toward the combined rating or required to have a CEMS by this clause: engines rated at less than 500 bhp; standby engines that are limited by permit conditions to only operate when other primary engines are not operable; engines that are limited by permit conditions to operate less than 1000 hours per year or a fuel usage of less than 8 x 10^9 Btus per year (higher heating value of all fuels used); and engines required to have a CEMS by the previous clause. A CEMS shall not be required if permit conditions limit the simultaneous use of the engines at the same location in a manner to limit the combined rating of all engines in simultaneous operation to less than 1500 bhp.

(IV) For engines rated below 1000 bhp, the CEMS may be time shared by multiple engines.

(iii) All CEMS required by this rule shall:

(I) Comply with the applicable requirements of Rules 218 and 218.1, including equipment specifications and certification, operating, recordkeeping, quality assurance and reporting requirements, except as otherwise authorized by this rule;

(II) Include equipment that measures and records exhaust gas concentrations, both uncorrected and corrected to 15 percent oxygen on a dry basis; and

(III) Have data gathering and retrieval capability approved by the Executive Officer

(iv~~i~~) The operator of an engine that is required to install CEMS may request the Executive Officer to approve an alternative monitoring device (or system components) to demonstrate compliance with the emission limits of this rule. The applicant shall demonstrate to the Executive Officer that the proposed alternative monitoring device is at a minimum equivalent in relative accuracy, precision, reliability, and timeliness to a CEMS for that engine, according to the criteria specified in 40 CFR Part 75 Subpart E. In lieu of the criteria specified in 40 CFR Part 75 Subpart E, substitute criteria is acceptable if the applicant demonstrates to the Executive Officer that the proposed alternative monitoring device is at minimum equivalent in relative accuracy precision, reliability, and timeliness to a CEMS for that engine. Upon approval by the Executive Officer, the substitute criteria shall be submitted to ~~the federal Environmental Protection Agency (~~EPA~~)~~ as an amendment to the State Implementation Plan (SIP).

If the alternative monitoring device is denied or fails to be recertified, a CEMS shall be required.

~~(iii) The monitoring system shall have data gathering and retrieval capability approved by the Executive Officer.~~

(v) Notwithstanding the requirements of Rules 218 and 218.1, operators of engines that are required to install a CEMS by clause (ii) of this subparagraph may:

(I) Store data electronically without a strip chart recorder, but there shall be redundant data storage capability for at least 15 days of data. The operator must demonstrate that both sets of data are equivalent.

(II) Conduct relative accuracy testing on the same schedule for source testing in clause (f)(1)(C)(i), instead of annually. The minimum sampling time for each test is 15 minutes.

(vi) Notwithstanding the requirements of Rules 218 and 218.1, operators of engines that are required to install a CEMS by clause (ii) of this subparagraph, and that are to be monitored by a timeshared CEMS, may:

(I) Monitor an engine with the CEMS for 15 consecutive minutes, purge for the minimum required purge time, then monitor the next engine for 15 consecutive minutes. The CEMS shall operate continuously in this manner, except for required calibrations.

(II) Record the corrected and uncorrected NOx, CO and diluent data at least once per minute and calculate and record the 15-minute average corrected concentrations for each sampling period.

(III) Have sample lines to each engine that are not the same length. The purge time will be based on the sample line with the longest response time. Response times shall be checked during cylinder gas audits. Sample lines shall not exceed 100 feet in length.

(IV) Conduct a minimum of five tests for each engine during relative accuracy tests.

(V) Perform cylinder gas audit every calendar quarter on each engine, except for engines for which relative accuracy testing was conducted that quarter.

(VI) Exclude monitoring of nitrogen dioxide (NO_2) for rich-burn engines, unless source testing demonstrates that NO_2 is more than 10 percent of total NOx.

(VII) Conduct daily calibration error (CE) tests by injecting calibration gases at the analyzers, except that at least once per week the CE test shall be conducted by injecting calibration gases as close to the probe tip as practical.

(VIII) Stop operating and calibrating the CEMs during any period that the operator has a continuous record that the engine was not in operation.

(vii) A CO CEMS shall not be required for lean-burn engines or an engine that is subject to Regulation XX (RECLAIM), and not required to have a NOx CEMS by that regulation.

(viii) Notwithstanding the requirements of this paragraph and paragraph (c)(2) of Rule 2012, an operator may take an existing NOx CEMS out of service for up to two weeks (cumulative) in order to modify the CEMS to add CO monitoring.

(B) Elapsed Time Meter

Maintain~~The engine shall have~~ an operational non-resettable totalizing time meter to determine the engine elapsed operating time.

(C) Source Testing

(i) Conduct ~~Provide~~ source testing ~~information regarding the exhaust gas, specifically~~ for NO_x, VOC reported as carbon, and CO concentrations (concentrations in ppm by volume, corrected to 15 percent oxygen on dry basis) at least once every two~~3~~ years, or every 8,760 operating hours, whichever occurs first. Relative accuracy tests required by Rule 218.1 or 40 CFR Part 75 Subpart E will satisfy this requirement for those pollutants monitored by a CEMS. The source test frequency may be reduced to once every three years if the engine has operated less than 2,000 hours since the last source test. If the engine has not been operated within three months of the date a source test is required, the source test shall be conducted when the engine resumes operation for a period longer than either seven consecutive days or 15 cumulative days of operation. The operator of the engine shall keep sufficient operating records to demonstrate that it meets the requirements for extension of the source testing deadlines.

(ii) Conduct source testing for at least 30 minutes during normal operation (actual duty cycle). This test shall not be conducted under a steady-state condition unless it is the normal operation. In addition, conduct source testing for NOx and CO emissions for at least 15 minutes at: an engine's actual peak load, or the maximum load that can be practically achieved during the test, and; at actual minimum load, excluding idle, or the minimum load that can be practically achieved during the test. These additional two tests are not required if the permit limits the engine to operating at one defined load, ± 10%. No pre-tests for compliance are permitted. The emission test shall be conducted at least 40 operating hours, or at least 1 week, after any engine servicing or tuning. If an emission exceedance is found during any of the three phases of the test, that phase shall be completed and reported. The operator shall correct the exceedance, and the source test may be immediately resumed.

(iii) Use a contractor to conduct the source testing that is approved by the Executive Officer under the Laboratory Approval Program for the necessary test methods.

(iv) Submit a source test protocol to the Executive Officer for written approval at least 60 days before the scheduled date of the test. The source test protocol shall include the name, address and phone number of the engine operator and a District-approved source testing contractor that will conduct the test, the application and permit number(s), emission limits, a description of the engine(s) to be tested, the test methods and procedures to be used, the number of tests to be conducted and under what loads, the required minimum sampling time for the VOC test, based on the analytical detection limit and expected VOC levels, and a description of the parameters to be measured in accordance with the I&M plan required by subparagraph (f)(1)(D). The source test protocol shall be approved by the Executive Officer prior to any testing. The operator is not required to submit a protocol for approval if: there is a previously approved protocol that meets these requirements; the engine has not been altered in a manner that requires a permit alteration; and emission limits have not changed since the previous test. If the operator submits the protocol by the required date, and the Executive Officer takes longer than 60 days to approve the protocol, the operator shall be allowed the additional time needed to conduct the test.

(v) Provide the Executive Officer at least 30 days prior notice of any source test to afford the Executive Officer the opportunity to have an observer present. If after 30 days notice for an initially scheduled performance test, there is a delay (due to operational problems, etc.) in conducting the scheduled performance test, the engine operator shall notify the Executive Officer as soon as possible of any delay in the original test date, either by providing at least seven days prior notice of the rescheduled date of the performance test, or by arranging a rescheduled date with the Executive Officer by mutual agreement.

(vi) Submit all source test reports, including a description of the equipment tested, to the Executive Officer within 60 days of completion of the test.

(vii) By (one year from date of adoption), provide, or cause to be provided, source testing facilities as follows:

(I) Sampling ports adequate for the applicable test methods. This includes constructing the air pollution control system and stack or duct such that pollutant concentrations can be accurately determined by applicable test methods;

(II) Safe sampling platform(s), scaffolding or mechanical lifts, including safe access, that comply with California General Safety Orders. Agricultural stationary engines are excused from this subclause if they are in remote locations without electrical power;

(III) Utilities for sampling and testing equipment. Agricultural stationary engines are exempt from this subclause if they are on wheels and moved to storage during the off season.

(D) Inspection and Monitoring (I&M) Plan

Submit to the Executive Officer for written approval and implement an I&M plan. One plan application is required for each facility. The I&M plan shall include:

(i) Identification of engine and control equipment operating parameters necessary to maintain pollutant concentrations within the rule and permit limits. This shall include, but not be limited to:

(I) Procedures for using a portable NOx, CO and oxygen analyzer to establish the set points of the air-to-fuel ratio controller (AFRC) at 25%, 60% and 95% load (or fuel flow rate), ± 5%, or the minimum, midpoint and maximum loads that actually occur during normal operation, ± 5%, or at any one load within the ± 10% range that an engine permit is limited to in accordance with clause (f)(1)(C)(ii);

(II) Procedures for verifying that the AFRC is controlling the engine to the set point during the daily monitoring required by clause (f)(1)(D~~E~~)(iv);

(III) Procedures for reestablishing all AFRC set points with a portable NOx, CO and oxygen analyzer whenever a set point must be readjusted, within 24 hours of an oxygen sensor replacement, and, for rich-burn engines with three way catalysts, between 100 and 150 engine operating hours after an oxygen sensor replacement;

(IV) For engines with catalysts, the maximum allowed exhaust temperature at the catalyst inlet, based on catalyst manufacturer specifications;

(V) For lean-burn engines with selective catalytic control devices, the minimum exhaust temperature at the catalyst inlet required for reactant flow (ammonia or urea), and procedures for using a portable NOx and oxygen analyzer to establish the acceptable range of reactant flow rate, as a function of load;.

Parameter monitoring is not required for diesel engines without exhaust gas recirculation and catalytic exhaust control devices.

(ii) Procedures for alerting the operator to emission control malfunctions. Engine control systems, such as air-to-fuel ratio controllers, shall have a malfunction indicator light and audible alarm.

(iii) Procedures for at least weekly or every 150 engine operating hours, whichever occurs later, emissions checks by a portable NOx, CO and oxygen analyzer.

(I) If an engine is in compliance for three consecutive emission checks, without any adjustments to the oxygen sensor set points, then the engine may be checked monthly or every 750 engine operating hours, whichever occurs later, until there is a noncompliant emission check or, for rich-burn engines with three-way catalysts, the oxygen sensor is replaced.

~~(I)~~(II) For diesel engines and other lean-burn engines that are subject to Regulation XX or have a NOx CEMs, and that are subject to a CO limit more stringent than the 2000 ppmvd limit of Tables II or III, a CO emission check shall be performed at least quarterly, or every 2,000 engine operating hours, whichever occurs later.

~~(II)~~(III) For diesel engines and other lean-burn engines that are subject to Regulation XX or have a NOx CEMs, and that are not subject to a CO limit more stringent than the 2000 ppmvd limit of Tables II or III, emission checks are not required.

(IV) No engine or control system maintenance or tuning may be conducted within 72 hours prior to the emission check, unless it is an unscheduled, required repair.

(V) The portable analyzer shall be calibrated, maintained and operated in accordance with the manufacturer's specifications and recommendations and the Protocol for the Periodic Monitoring of Nitrogen Oxides, Carbon Monoxide, and Oxygen from Stationary Engines Subject to South Coast Air Quality Management District Rule 1110.2, approved on (date of adoption), or subsequent protocol approved by EPA and the Executive Officer.

(iv) Procedures for at least daily monitoring, inspection and recordkeeping of:

(I) engine load or fuel flow rate,

(II) the set points, maximums and acceptable ranges of the parameters identified by clause (f)(1)(D)(i), and the actual values of the same parameters;

(III) the engine elapsed time meter operating hours;

(IV) the operating hours since the last emission check required by (f)(1)(D)(iii)

(V) for rich-burn engines with three-way catalysts, the difference of the exhaust temperatures (ΔT) at the inlet and outlet of the catalyst (changes in the ΔT can indicate changes in the effectiveness of the catalyst);

(VI) engine control system and AFRC system faults or alarms that affect emissions;

The daily monitoring and recordkeeping may be done in person by the operator, or by remote monitoring.

(v) Procedures for responding to, diagnosing and correcting breakdowns, faults, malfunctions, alarms, emission checks finding emissions in excess of rule or permit limits, and parameters out-of-range.

(I) For a breakdown resulting in a violation of this rule or a permit condition, or for an emission check that finds emissions in excess of those allowed by this rule or a permit condition, the operator shall correct the problem and demonstrate compliance with another emission check, or shut down an engine by the end of an operating cycle, or within 24 hours from the time the operator knew of the breakdown or excess emissions, or reasonably should have known, whichever is sooner.

(II) For other problems, such as parameters out-of-range, an operator shall correct the problem and demonstrate compliance with another emission check within 48 hours of the operator first knowing of the problem.

(III) An operator shall not be considered in violation of the emission limits of this rule or in permit conditions if the operator complies with this subparagraph and the reporting requirements of subparagraph (f)(1)(H). Any emission check conducted by District staff that finds excess emissions is a violation.

(vi) Procedures and schedules for preventive and corrective maintenance;

(vii) Procedures for reporting noncompliance to the Executive Officer in accordance with subparagraph (f)(1)(H).

(viii) Procedures and format for the recordkeeping of monitoring and other actions required by the plan;

(ix) Procedures for plan revisions. Before any change in I&M plan operations can be implemented, the revised I&M plan shall be submitted to and approved by the Executive Officer. The operator shall apply for a plan revision prior to any change in emission limits or control equipment.

(x) An engine is not subject to this subparagraph if it is required by this rule to have a NOx and CO CEMS, or voluntarily has a NOx and CO CEMS that complies with this rule.

(E~~D~~) Operating Log

Maintain a monthly engine operating log that includes:

(i) Total hours of operation;

(ii) Type of liquid and/or type of gaseous fuel;

(iii) Fuel consumption (cubic feet of gas and~~or~~ gallons of liquid); and

(iv) Cumulative hours of operation since the last source test required in subparagraph (f)(1)(C).

Facilities subject to Regulation XX may maintain a quarterly log for engines that are designated as a process unit on the facility permit.

(F) New Non-Emergency Electrical Generating Engines

Operators of engines subject to the requirements of subparagraph (d)(1)(F) shall also meet the following requirements.

(i) The engine generator shall be monitored with a calibrated electric meter that measures the net electrical output of the engine generator system, which is the difference between the electrical output of the generator and the electricity consumed by the auxiliary equipment necessary to operate the engine generator.

(ii) For engines monitored with a CEMS, the emissions of the monitored pollutants in ppmvd corrected to 15% O2, , lbs/hr, and lbs/MW_e-hr and the net MW_e-hrs produced shall be calculated and recorded for the four 15-minute periods of each hour of operation. The mass emissions of NOx shall be calculated based on the measured fuel flow and one of the F factor methods of 40 CFR 60, Appendix A, Method 19, or other method approved by the Executive Officer. Mass emissions of CO shall be calculated in the same manner as NOx, except that the ppmvd CO shall be converted to lb/scf using a conversion factor of 0.727×10^{-7}.

(iii) For NOx and CO emissions from engines not monitored with a CEMS and VOC emissions from all engines, the emissions of NOx, CO and VOC in lbs/MW_e-hr shall be calculated and recorded whenever the pollutant is measured by a source test or emission check. Mass emissions of NOx and CO shall be calculated in the same manner as the previous clause. Mass emissions of VOC shall be calculated in the same manner, except that the ppmvd VOC as carbon shall be converted to lb/scf using a conversion factor of 0.415×10^{-7}.

(iv) For engines generating combined heat and power that rely on the EEF to comply with Table IV emission standards, the daily and annual useful heat recovered (MW_{th}-hrs), net electrical energy generated (MW_e-hrs) and EEF shall be monitored and recorded.

(v) Other methods of calculating mass emissions than those specified, such as by direct measurement of exhaust volume, may be used if approved by the Executive Officer. All monitoring, calculation, and recordkeeping procedures must be approved by the Executive Officer.

(vi) Operators of combined heat and power engines shall submit to the Executive Officer the reports of the following information within 15 days of the end of the first year of operation, and thereafter within 15 days of the end of each calendar year: the annual net electrical energy generated (MW_e-hrs); the annual useful heat recovered (MW_{th}-hrs), the annual EEF calculated in accordance with clause (d)(1)(F)(ii); and the maximum annual EEF allowed by the operating permit. If the actual annual EEF exceeds the allowed EEF, the report shall also include the time periods and emissions for all instances where emissions exceeded any emission standard in Table IV.

(G) Portable Analyzer Operator Training

The portable analyzer tests required by the I&M Plan requirements of subparagraph (f)(1)(D) shall only be conducted by a person who has completed an appropriate District-approved training program in the operation of portable analyzers and has received a certification issued by the District.

(H) Reporting Requirements

(i) The operator shall report to the Executive Officer, by telephone (1-800-CUT-SMOG or 1-800-288-7664) or other District-approved method, any breakdown resulting in emissions in excess of rule or permit emission limits within one hour of such noncompliance or within one hour of the time the operator knew or reasonably should have known of its occurrence. Such report shall identify the time, specific location, equipment involved, responsible party to contact for further information, and to the extent known, the causes of the noncompliance, and the estimated time for repairs. In the case of emergencies that prevent a person from reporting all required information within the one-hour limit, the Executive Officer may extend the time for the reporting of required information provided the operator has notified the Executive Officer of the noncompliance within the one-hour limit.

(ii) Within seven calendar days after the reported breakdown has been corrected, but no later than thirty calendar days from the initial date of the breakdown, unless an extension has been approved in writing by the Executive Officer, the operator shall submit a written breakdown report to the Executive Officer which includes:

(I) An identification of the equipment involved in causing, or suspected of having caused, or having been affected by the breakdown;

(II) The duration of the breakdown;

(III) The date of correction and information demonstrating that compliance is achieved;

(IV) An identification of the types of excess emissions, if any, resulting from the breakdown;

(V) A quantification of the excess emissions, if any, resulting from the breakdown and the basis used to quantify the emissions;

(VI) Information substantiating whether the breakdown resulted from operator error, neglect or improper operation or maintenance procedures;

(VII) Information substantiating that steps were immediately taken to correct the condition causing the breakdown, and to minimize the emissions, if any, resulting from the breakdown;

(VIII) A description of the corrective measures undertaken and/or to be undertaken to avoid such a breakdown in the future; and

(IX) Pictures of any equipment which failed, if available.

(iii) Within 15 days of the end of each calendar quarter, the operator shall submit to the Executive Officer a report that lists each occurrence of a breakdown, fault, malfunction, alarm, engine or control system operating parameter out of the acceptable range established by an I&M plan or permit condition, or an emission check that finds excess emissions. Such report shall be in a District-approved format, and for each incident shall identify the time of the incident, the time the operator learned of the incident, specific location, equipment involved, responsible party to contact for further information, to the extent known the causes of the event, the time and description of corrective actions, including shutting an engine down, and the results of all portable analyzer NOx and CO emissions checks done before or after the corrective actions. The operator shall also report if no incidents occurred.

(2) Portable engines:

The operator of any portable engine shall maintain a monthly engine operating log that includes:

(i) Total hours of operation; or

(ii) Type of liquid and/or type of gaseous fuel; and

(iii) Fuel consumption (cubic feet of gas and~~or~~ gallons of liquid).

Facilities subject to Regulation XX may maintain a quarterly log for engines that are designated as a process unit on the facility permit.

(3) Recordkeeping for All Engines

All data, logs, test reports and other information required by this rule shall be maintained for at least five years and made available for inspection by the Executive Officer.

(g) Test Methods

Testing to verify compliance with the applicable requirements shall be conducted in accordance with the test methods specified in Table~~ABLE~~ VIII, or any test methods approved by CARB and EPA, and authorized by the Executive Officer.

TABLE VIII **TESTING METHODS**	
Pollutant	Method
NO_x	District Method 100.1
CO	District Method 100.1
VOC	District Method 25.1* or District Method 25.3*

* Excluding ethane and methane

A violation of any standard of this rule established by any of the specified test methods, or any test methods approved by the CARB or EPA, and authorized by the Executive Officer, shall constitute a violation of this rule.

(h) Exemptions

The provisions of subdivision (d) shall not apply to:

(1) All orchard wind machines powered by an internal combustion engine.

(2) Emergency standby engines, engines used for fire-fighting and flood control, and any other emergency engines ~~as~~ approved by the Executive Officer, which have permit conditions that limit operat~~e~~ion to 200 hours or less per year as determined by an elapsed operating time meter, and agricultural emergency standby engines that are exempt from a District permit and operate 200 hours or less per year as determined by an elapsed operating time meter.

~~(3) Engines used for fire-fighting and flood control~~.

(3~~4~~) Laboratory engines used in research and testing purposes.

(4~~5~~) Engines operated for purposes of performance verification and testing of engines.

~~(6) Engines operating in the Eastern portion of Riverside County not within the South Coast Air Basin or the Salton Sea Air Basin.~~

(5~~7~~) Auxiliary engines used to power other engines or gas turbines during start-ups.

~~(8) Supplemental engines which operate between November 1 of one year and April 15 of the following year for the manufacture of snow and/or operation of ski lifts.~~

(6~~9~~) Portable engines that are registered under the state registration program pursuant to Title 13, Article 5 of the CCR.

(7~~10~~) Nonroad engines, with the exception that subparagraph (d)(2)(A~~B~~) shall apply to portable generators.

(8~~11~~) Engines operating on San Clemente Island.

(9~~12~~) Agricultural stationary engines provided that:

(A) The operator submits documentation to the Executive Officer by the applicable date in Table V~~II~~ when permit applications are due that the applicable electric utility has rejected an application for an electrical line extension to the location of the engines, or the Executive Officer determines that the operator does not qualify, due to no fault of the operator, for funding authorized by California Health and Safety Code Section 44229; and

(B) The operator replaces the engines, in accordance with the compliance schedule of Table IX, with engines certified by CARB to meet the Tier 4 emission standards of 40 CFR Part 1039 Section 1039.101, Table 1. These Tier 4 replacement engines shall be considered to comply with Best Available Control Technology; and

(C) The operator does not operate the Tier 4 engines in a manner that exceeds the not-to-exceed standards of 40 CFR Section 1039.101, Paragraph (e), as determined by the test methods of subdivision (g) of this rule.

TABLE~~able~~ IX
COMPLIANCE SCHEDULE FOR INSTALLATION OF NEW TIER 4 STATIONARY AGRICULTURAL ENGINES

Action Required	**Due Date**
Submit to the Executive Officer applications for permits to construct engine modifications, control equipment, or replacement engines	March 1, 2013
Initiate construction of engine modifications, control equipment, or replacement engines	September 30, 2013, or 30 days after the permit to construct is issued, whichever is later
Complete construction and comply with applicable requirements	January 1, 2014, or 60 days after the permit to construct is issued, whichever is later

Complete initial source testing	March 1, 2014, or 120 days after the permit to construct is issued, whichever is later

(10) An engine start-up, until sufficient operating temperatures are reached for proper operation of the emission control equipment. The start-up period shall not exceed 30 minutes, unless the Executive Officer approves a longer period for an engine and makes it a condition of the engine permit.

(11) An engine start-up, after an engine overhaul or major repair requiring removal of a cylinder head, for a period not to exceed four operating hours.

(12) The initial commissioning of a new engine for a period specified by permit conditions, provided the operator takes measures to reduce emissions and the duration of the commissioning to the extent possible. The commissioning period shall not exceed 150 operating hours.

APPENDIX C

ASSUMPTIONS AND CALCULATIONS

PAR 1110.2 Emissions Calculations

ENGINES AND FUEL USAGE

___Emission calculations are based on engines and fuel use data reported in 2005 engine survey plus data added for unreported diesels that are or may be affected by PAR1110.2.
___Results for the survey engines are scaled up to represent the full population found in a search of AQMD permitting data base (all active permits and open applications for stationary, non-emergency engines). Scaling factors depend on category--RECLAIM, non-RECLAIM, biogas, diesel (see "Scale Factors" worksheet).

SCALING FACTORS

Biogas engines:	Represented in Calc's =	54	Number found in BCAT search =	66	Factor =	0.818
RECLAIM nat gas engines:	Represented in Calc's =	90	Number found in BCAT search =	111	Factor =	0.811
Other nat gas engines:	Represented in Calc's =	481	Number found in BCAT search =	652	Factor =	0.738
Diesel engines:	Represented in Calc's =	30	Number found in BCAT search =	30	Factor =	1.000
		655		859		

NOx, CO and VOC CONCENTRATIONS (Note Concentrations Summary Table at end of this section):
Baseline Emissions

Biogas Engines

Baseline emissions are based on NOx limits, landfill gas VOC limits (40 ppm @ 15% O2 as methane), average VOC source test results for digester gas engines based on the survey data, and average CO source test results based on the survey data. In all cases except CEMS-monitored NOx, baseline emissions are assumed to be, on average, 10% above those limits or source test results.

Rich-Burn Engines

For non-RECLAIM and RECLAIM BACT engines with NOx CEMS, it is assumed that the NOx level is maintained on average at 80% of the NOx limit.
For RECLAIM Majors, it is assumed that the NOx level is at the apparent "limit", which was calculated from Annual Emissions Report data.
For most rich-burn engines, baseline NOx and CO emissions are based on NOx and CO limits multipled by factors that are based on AQMD compliance test results.
AQMD compliance tests showed that for engines without CEMS, the average ratio of measured NOx to the NOx limit is 5.19 for BACT engines (NOx limit in 8-23 range)
AQMD compliance tests showed that the average ratio of measured CO to the CO limit follows the relationship R-CO = 6.75 - .00306 x (L - 75),
For non-BACT engines in RECLAIM, many NOx limits are above the range of the AQMD compliance data (none tested in this category), and it is assumed that baseline NOx
Although compliance testing did not include VOC data, source test data reported in the engine survey showed that VOC levels tend to correspond to roughly the square root of

Lean-Burn Engines (Excluding Biogas Engines)

Non-BACT engines (all in RECLAIM): Non-CEMS NOx assumed to be at limit on average, and CO and VOC assumed 10% over source test results on average.
BACT, non-RECLAIM engines: non-CEMS NOx assumed 1.8 x the NOx limit based on AQMD compliance test results; CO and VOC assumed 10% above average
BACT RECLAIM engines (Snow Summit diesels, 50 ppm NOx limit, no CEMS): NOx, CO and VOC assumed to be 10% over limits on average.

Controlled Emissions (Step 1)

Step 1 is the increased monitoring requirements that take effect in 2007 - 2009.
Lean-burn engines: Expected to operate at BACT limits or, in absence of BACT limit, at average source test results.
Rich-burn engines that will have NOx/CO CEMS: it is assumed that both NOx and CO will be maintained on average at 80% of their respective limits.
Rich-burn engines subject to Inspection & Monitoring Plans: it is assumed that both NOx and CO will be, on average, no greater than 20% above their respective limits.

Controlled Emissions (Step 2)

Step 2 is reduction to NOx/CO/VOC = 11/250/30 ppm @ 15% O2, taking effect in 2010 - 2012.
Engines with BACT limits will be unaffected, and engines in RECLAIM will be unaffected regarding NOx.
Engines that will have NOx and/or CO CEMS: it is assumed that the monitored pollutant(s) will be maintained on average at 80% of their respective limits.
Engines subject to Inspection & Monitoring Plans:
Rich-burn: it is assumed that both NOx and CO will be, on average, no greater than 20% above their respective limits.

Lean-burn: it is assumed that both NOx and CO will be, on average, no greater than their respective limits.

Concentrations Summary Table:

	Baseline			Step 1			Step 2			
	NOx	CO	VOC	NOx	CO	VOC	NOx	CO	VOC	Fuel
Biogas >=1000	0.8 x L	1.1 x S/T	1.1 x S/T	same	S/T	S/T	0.8 x 11	250 or S/T	CO% or 30	Biogas
Biogas <1000, New CEMS	1.1 x L	1.1 x S/T	1.1 x S/T	0.8 x L	S/T	S/T	0.8 x 11	250 or S/T	CO% or 30	Biogas
Biogas <1000, I&M	1.1 x L	1.1 x S/T	1.1 x S/T	L	S/T	S/T	11	250 or S/T	CO% or 30	Biogas
Rich BACT RECL Major	0.8 x L	f(L)	f(CO)	same	f(L)-0.8	f(CO)	same	same	f(CO) or 30	NG
Rich BACT RECL Non-Major	f(L)	f(L)	f(CO)	same	f(L)-1.2	f(CO)	same	same	f(CO) or 30	NG
Rich Non-BACT RECL Major	L	f(L)	f(CO)	same	f(L)-0.8	f(CO)	same	0.8 x 250 or same	f(CO) or 30	NG
Rich Non-BACT RECL Non-Major	L	f(L)	f(CO)	same	f(L)-1.2	f(CO)	same	1.2 x 250 or same	f(CO) or 30	NG
Lean BACT RECLAIM Non-Major	1.1 x L	1.1 x L	1.1 x L	L	L	L	same	same	same or 30	Dsl
Lean Non-BACT RECLAIM Major	L	1.1 x S/T	1.1 x S/T	same	S/T	S/T	same	250 or S/T	CO% or 30	NG, Dsl
Lean Non-BACT RECLAIM Non-Major	L	1.1 x S/T	1.1 x S/T	same	S/T	S/T	same	250 or S/T	CO% or 30	NG, Dsl
Rich BACT >=1000	0.8 x L	f(L)	f(CO)	same	f(L)-0.8	f(CO)	0.8 x (11 or L)	0.8 x (250 or L)	f(CO) or 30	NG
Rich BACT <1000, New CEMS	f(L)	f(L)	f(CO)	0.8 x L	f(L)-0.8	f(CO)	0.8 x (11 or L)	0.8 x (250 or L)	f(CO) or 30	NG
Rich BACT <1000, I&M	f(L)	f(L)	f(CO)	1.2 x L	f(L)-1.2	f(CO)	1.2 x (11 or L)	1.2 x (250 or L)	f(CO) or 30	NG
Lean BACT >=1000	0.8 x L	1.1 x L	1.1 x L	same	L	L	same	same	same or 30	NG
Lean BACT <1000, New CEMS	1.8 x L	1.1 x L	1.1 x L	L	L	L	same	same	same or 30	NG
Lean BACT <1000, I&M	1.8 x L	1.1 x L	1.1 x L	L	L	L	same	same	same or 30	NG
Rich Non-BACT >=1000	0.8 x L	f(L)	f(CO)	same	f(L)-0.8	f(CO)	0.8 x 11	0.8 x 250	f(CO) or 30	NG
Rich Non-BACT <1000, New CEMS	f(L)	f(L)	f(CO)	0.8 x L	f(L)-0.8	f(CO)	0.8 x 11	0.8 x 250	f(CO) or 30	NG
Rich Non-BACT <1000, I&M	f(L)	f(L)	f(CO)	1.2 x L	f(L)-1.2	f(CO)	1.2 x 11	1.2 x 250	f(CO) or 30	NG

Notes: L = horsepower-weighted average NOx or CO limit for group or effective "limit" based on actual emissions for some RECLAIM majors; S/T = avg. source test result for group.
"CO% or S/T" means same percentage reduction as CO or the averaged source test results for the group, whichever lower.
f(L) = calculated ppm using factors derived from AQMD compliance test data (discussed above under "Baseline Emissions").
f(CO) = calculated VOC ppm using factors developed from source test data (discussed above under "Baseline Emissions")
F(L)-0.8 = calculated ppm using factors based on AQMD compliance data capped at 0.8 x L (discussed above under "Baseline Emissions")
F(L)-1.2 = calculated ppm using factors based on AQMD compliance data capped at 1.2 x L (discussed above under "Baseline Emissions")
"(X or Y)" means whichever lower.

NOx, CO, VOC TPY Calculations

Natural gas: NOx factor is based on 80 ppm NOx @ 3% O2 = 1 lb per MMBtu fuel input (as NO2). For CO, 80 ppm factor becomes 80 x 46 (mol-wt. NO2) / 28 (mol-wt. CO). For VOC (as methane), 80 ppm factor becomes 80 x 46 / 16 (mol-wt. CH4)

Diesel: 80 ppm factor becomes 80 x 8710 (EPA Method 19 dry gas factor for natural gas) / 9190 (EPA Method 19 dry gas factor for diesel).

Biogas: divide concentration @ 15% O2 by 0.97 to correct for typical 50% CO2 in biogas (resulting in approx. 3% added flue gas volume at 15% O2).

SOx TPY Calculations

Natural gas - 1 grain per 100 scf nat gas (CPUC limit); digester gas - 40 ppm as H2S (R431.1); landfill gas - 150 ppm as H2S (R431.1). Assumed 50% methane in digester or landfill gas (biogas).

Diesel - 15 ppm sulfur in fuel.

PM2.5 TPY Calculations

Natural gas, rich-burn - .0194 lb/MMBtu (AP42); natural gas or biogas lean-burn - .00998 lb/MMBtu (AP42); diesel - 0.1 lb/MMBtu (AP42)

CO2 TPY Calculations

Natural gas or biogas: TPY CO2 = fuel input (Btu/Yr) /23,861 (Btu/lb CH4) / 16 (mol-wt. CH4) x 44 (mol-wt. CO2) / 2000 (lb/ton). Double for biogas (assuming 50% CO2 on average).
Diesel: TPY CO2 = fuel input (Btu/Yr) / 19,000 (Btu/lb) x .871 (typical wt.-fraction carbon in diesel) / 12 (mol-wt. carbon) x 44 (mol-wt. CO2) / 2000 (lb/ton)
Subtract TPY CO / 28 (mol-wt. CO) x 44 (mol-wt. CO2)

Usage of Urea (CO[NH2]2)

Baseline NOx (TPY) x (baseline conc. Limit - 11 (future concentration limit))/ baseline concentration limit / 46 (mol-wt. NO2) /2 (mols NOx reduced per mol urea) x 60 (mol-wt. urea) x 1.2 (20 percent excess urea - equivalent to approx. 5 ppm slip for avg. biogas engine NOx if all excess ammonia appears in flue gas)

CO2 from Urea (CO[NH2]2)

Baseline NOx (TPY) x (baseline conc. Limit - 11 (future concentration limit))/ baseline concentration limit / 46 (mol-wt. NO2) /2 (mols NOx reduced per mol urea) x 44 (mol-wt. CO2) x 1.2 (20 percent excess urea - equivalent to approx. 5 ppm slip for avg. biogas engine NOx if all excess ammonia appears in flue gas)

Effects of Three-Way Catalyst Upgrades and Installation of Oxidation Catalysts

It is assumed that three-way catalyst upgrades and new oxidation catalysts both add 1 In. H2O pressure drop to engine exhaust.
Added engine work (hp) = .0158 x cfm x In. H2O / 85% (typical blower efficiency) - from Babcock & Wilcox Useful Tables
cfm engine exhaust per hp =
rich-burn: 2545 Btu/hp-hr / 0.31 (typical engine effic.) / 1e6 x 8710 scfm per MMBtu @ 0% O2 (EPA Meth 19) x 1460 / 520 (temperature correction / 60 (min/hr)
lean-burn: above x 20.9/13.9 (corrects to 7% O2 in flue) x 1260/1460 (corrects gas vol. from 1000F to 800F)
Total catalyst weight per horsepower = 0.615 pound
It was assumed that the volume of the haul trucks would be 20 cubic yards.

CEMS Power Requirement

= 2.3 kW per CEMS (figure provided by CEMS vendor). For shared CEMS, power use is distributed among engines sharing that CEMS.

Effect of Possible Electrification of Non-Biogas Engines

Scenarios were selected based on cost calculations - engine categories for which the present-value of the net 10-yr cost of electrification is negative (less than cost of compliance), in order of most negative to least negative on a $/hp basis.
For generator engines, replacement motor power use = Btu/Yr fuel used by engine x engine efficiency x 0.97 generator efficiency /3413000 Btu/MWH.
For work engines, replacement motor power use = Btu/Yr fuel used by engine x engine efficiency / 0.97 motor efficiency / 3413000 Btu/MWH.
CO2 reduction = baseline CO2 emission less CO2 from fossil power plants producing required power to replace power or work produce by engine less CO2 from increased boiler fuel. Increased boiler fuel = baseline fuel to engine x (1-engine effic) x 0.5 / 0.8 (assumes half of engine waste heat was being utilized by facility and must be replaced by increased boiler fuel at 80% boiler efficiency. Increased boiler fuel also produces NOx (30 ppm@3%O2), CO (100 ppm), SOx (1 grn/100 scf as sulfur) and CO2 emissions.
Grid power replacing engine power or work assumed to be produced 80% by in-basin natural gas plants and 20% by increased power from renewable sources.
Avg. fossil plant effic assumed to be 36% based on USEPA Acid Rain web site. Nat gas consumpt = 3413000 / 0.36 x 0.8 Btu/MWH
Emissions from power plants, based on annual emission reporting x 0.8 (lb/MWH) >>>>>>>
NOx, SOx from power plants are capped by RECLAIM.
CO2 ton/MWH = 7.58e6 / 23861 / 16 x 44 / 2000 =
Backup hp needed:
For generator engine replaced, hp = original engine hp
For work engine replaced, hp = original engine hp / 0.97 (typical generator efficiency)
Diesel fuel usage (gal/yr) = backup generator hp x 52.4 hrs/yr typical operation x 2545 Btu/hp-hr / 0.335 / 137000 Btu/gal
Diesel engine operation of 50 hrs/yr is based on 50 hrs testing (max allowed per Rule 1470)

Diesel emissions assume engine meets USEPA Nonroad standards for 2010, ultra low-sulfur diesel, 87% carbon in fuel, 137,000 Btu/gal.
It was assumed that the average engine would weigh 14,000 pounds
It was assumed that engines would be tested for 0.5 hours.

Diesel Emissions

	g/hp-hr:				ton/gal:			
Diesel Emissions	NOx	CO	VOC	PM	NOx	CO	VOC	PM
Engine Size <50 hp	5.29888579	4.103	0.2961142	0.2238	1.05E-04	8.15E-05	5.88E-06	4.44E-06
Engine Size 50 to <100 hp	3.3206351	3.73	0.1855649	0.2984	6.59E-05	7.41E-05	3.69E-06	5.93E-06
Engine Size 100 to <175 hp	2.82607242	3.73	0.1579276	0.2238	5.61E-05	7.41E-05	3.14E-06	4.44E-06
Engine Size 175 to <300 hp	2.72511416	2.611	0.2588858	0.1492	5.41E-05	5.19E-05	5.14E-06	2.96E-06
Engine Size 300 to <750 hp	2.72511416	2.611	0.2588858	0.1492	5.41E-05	5.19E-05	5.14E-06	2.96E-06
Engine Size >=750 hp	4.28471795	2.611	0.4896821	0.1492	8.51E-05	5.19E-05	9.73E-06	2.96E-06

SOx based on .0015% sulfur in fuel, 7.1 lb/gal	ton/gal =	1.07E-07
CO2 based on 87 % carbon in fuel, 7.1 lb/gal	ton/gal =	1.13E-02

TIMING OF ENGINE CHANGES FOR CEQA ANALYSIS

(Most dates are after rule deadlines to be conservative and synchronize dates of multiple requirements closely spaced in time.)

1/1/2008 Biogas engines using efficiency correction factor (ECF) reduce natural gas usage to 10%.
Non-biogas engines using ECF lose this benefit (lower NOx, VOC limits).
1/1/2009 Inspection & Monitoring begins, increased frequency of source testing now affecting majority of engines, air/fuel ratio controllers installed.
7/1/2009 CEMS and CO analyzers installed on engines >=500hp, not owned by public agencies.
7/1/2010 Limits drop to 11/250/30 (NOx/CO/VOC) for non-biogas engines >=500hp (except low-use engines).
Biogas engines not using ECF reduce nat gas use to 10%.
CEMS and CO analyzers installed on engines <500hp, not owned by public agencies and >=500 hp owned by public agencies.
7/1/2011 Limits drop to 11/250/30 (NOx/CO/VOC) for non-biogas engines <500hp (except low-use engines).
CEMS and CO analyzers installed on engines <500hp owned by public agencies.
7/1/2012 Limits drop to 11/250/30 (NOx/CO/VOC) for biogas engines except those deferred in Alternative D..
7/1/2014 Limits drop to 11/250/30 (NOx/CO/VOC) for biogas engines deferred in Alternative D.

Electrification timing was based on timing of rule requirements that require significant capital investment:

1/1/2009 Engines requiring installation of air/fuel ratio controller
7/1/2009 Engines requiring CEMS
7/1/2010 Engines requiring CEMS, new catalyst or catalyst upgrading
7/1/2011 Engines requiring CEMS, new catalyst or catalyst upgrading

BIOGAS FACILITY ASSUMPTIONS

General:
Biogas construction is assumed to begin in 2011 after the technology assessment in 2010. Half of the construction is assumed to start in 2011 and the rest in 2012.
Biogas operational emissions are assumed to occur in 2012. Both construction and operations will occur in 2012. Some operation (catalyst replacement) will not begin until 2014, since it was assumed that catalysts are replaced every three years.
Electricity production by ICE is based on heat input / 3.413E6 Btu/MWH x engine effic x generator effic (0.97)
Compressor work produced by ICE is based on heat input / 2545 (Btu/hp-hr) x engine effic.
Emissions and electricity production from gas turbine or microturbine are based on heat input and factors below:

	Lbs/MM Btu			
	BOILER	GAS TURBINE	MICROTURBINE	ICE
NOx	0.03	0.084	0.012	0.127
CO	0.0041	0.139	0.047	0.644
VOC	0.0034	0.0048	0.012	0.041
PM	0.0092	0.023	0.0037	0.013
Electr Effic (HHV)		26%	23%	
MWH/MMBtu		0.0761793	0.0673894	

These emission factors are based on averages of source test data in AQMD files.
Gas turbine and microturbine electrical efficiencies are typical of equipment used for biogas applications.

SCR Option
Assumed pressure losses (In. H2O) = 3" through gas cleanup, 3" through SCR and 1" through CatOx
Reduction in engine output based on hp = .0158 x cfm x In. H2O / 85% efficiency Babcock & Wilcox, Useful Tables, blower equation)
Flue gas cfm/hp = 2545 Btu/hp-hr/0.31(effic)/1e6 x 8710 (USEPA Meth 19 dscfm/MMBtu @ 0% O2) x 20.9/13.9 (corrects to

Seven percent flue O2) x 1260/520 (corrects to 800F flue temp.) / 60 min/hr	Fract. Reduct. In Engine Effic. =	3.74E-03
Fuel cfm/hp = 2545/0.31/475 (typical Btu/scf biogas) /60	Fract. Reduct. In Engine Effic. =	1.61E-04
Urea usage is based on 20% excess urea (5 ppm slip at 15% O2); theor. urea (mols) = 0.5 x mols NOx reduced.		3.90E-03
Equivalent ammonia = urea x 34 / 60		

Total catalyst weight per horsepower = 0.615 pound
It was assumed that the volume of the haul trucks would be 20 cubic yards.

Gas Turbine Option
Power production = gas turbine power
Shaft work = 0
Natural gas usage = same as baseline

Microturbine Option
Power production = microturbine power
Shaft work = 0
Natural gas usage = same as baseline

LNG Option
For conversion of biogas to liquified natural gas (LNG), it is assumed that 17.8% of biogas to the conversion process is used in a boiler to produce heat required by the process (based on Prometheus process data).
For conversion of digester gas to LNG, it is assumed that the replaced ICE was providing heat to the digester process equal to engine waste heat (heat input x (1 - engine effic)) x 0.5 (waste heat recovery factor) and that heat must now be providedby firing biogas in a boiler at 80% efficiency.
Emissions from boiler are based on factors in table above.
Power used by LNG production process = .0441 MWH per MMBtu LNG product (based on Prometheus process data).
The size of the LNG tank was estimated based on amount of LNG that could be produced over a period of five days based on the permit application for the Frank Bowerman Landfill LNG plant.
The transport trucks were assumed to have 10,000 gallon tanks days based on the permit application for the Frank Bowerman Landfill LNG plant.

Diesel/Natural Gas Usage by Emergency Backup Generator
Size of backup generator needed (HP): landfill case = none needed
Replacement of compressor with turbine: HP = ICE HP x (1 - turbine elec effic / (ICE effic x 0.97))
Elimination of compressor: HP = ICE HP / 0.97
Backup LNG power requirement: HP = LNG product MMBTU/yr x .0441 MWH/MMBTU / 8000 hrs/yr on line/ .000746 MW/HP / 0.97 (motor/generator effic)

It is assumed that 20% of backup capacity will be diesel and 80% will be natural gas (using the existing biogas engine).
Gal/Yr diesel fuel = HP x 52.4 (diesel engine hrs/yr) / 8000 (turbine or LNG plant on-line hrs/yr) x 3413000 (Btu/MWH) / 0.335 (typical diesel engine efficiency) / 137,000 (Btu/gal) x 0.2
Natural gas use for backup power (Btu/Yr) = gal/yr diesel x 137,000 / 0.2 x 0.8
Backup engine operation of 50 hrs/yr is based on 50 hrs testing (max allowed per Rule 1470)
It was assumed that engines would be tested for one hour on any given day.

Diesel Emissions	g/hp-hr: NOx	CO	VOC	PM	ton/gal: NOx	CO	VOC	PM
Engine Size <50 hp	5.30	4.10	0.30	0.224	1.12E-04	8.68E-05	6.26E-06	4.74E-06
Engine Size 50 to <75 hp	3.3206351	3.73	0.1855649	0.2984	7.03E-05	7.89E-05	3.93E-06	6.32E-06
Engine Size 75 to <175 hp	2.8260724	3.73	0.1579276	0.2238	5.98E-05	7.89E-05	3.34E-06	4.74E-06
Engine Size 175 to <750 hp	2.7251142	2.611	0.2588858	0.1492	5.77E-05	5.53E-05	5.48E-06	3.16E-06
Engine Size >=750 hp	4.2847179	2.611	0.4896821	0.1492	9.07E-05	5.53E-05	1.04E-05	3.16E-06

SOx based on .0015% sulfur in fuel, 7.1 lb/gal ton/gal = 1.07E-07
CO2 based on 87 % carbon in fuel, 7.1 lb/gal ton/gal = 1.13E-02

Pretreatment Carbon Assumptions

The amount of carbon used at a facility was estimated from the amount of carbon used at Orange County Sanitation District Facility Number 1 (OCSD No. 1) by ratio the horsepower of the engines at OCSD No. 1.

The number of trips was estimated by the number of 6,800 pound vessels that need to be replaced.

It was assumed that all biogas facilities would need pre-treatment for add-on control and ICE alternative technology.

It was assumed that an equal number of trips would occur for both spent carbon removal and new carbon delivery.

Table C-1
Operational Emissions from Requirements of PAR 1110.2 Only (i.e, No Secondary Emissions)

Non-Biogas Engines

Year	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM-2.5, lb/day	CO2, ton/year
Baseline	7,336	44,688	1,611	87	741	680,612
2008	7,210	44,688	1,611	87	741	680,612
2009	5,056	14,192	1,065	87	741	689,358
2010	4,725	10,162	613	87	741	690,514
2011	4,388	7,305	566	87	741	691,333
2012	4,388	7,305	566	87	741	691,333
2014	4,388	7,305	566	87	741	691,333

Table C-1 (Continued)
Operational Emissions from Requirements of PAR 1110.2 Only (i.e, No Secondary Emissions)

Biogas Engines

Year	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM-2.5, lb/day	CO2, ton/year
Baseline	1,859	9,555	882	464	136	569,435
2008	~~1,781~~ 1,786	~~9,176~~ 9,209	~~846~~ 855	~~456~~ 457	~~130~~ 131	~~546,588~~ -
2009	~~1,765~~ 1,770	~~8,342~~ 8,375	~~769~~ 778	~~456~~ 457	~~130~~ 131	~~546,827~~
2010	~~1,722~~ 1,727	~~8,152~~ 8,185	~~753~~ 762	~~454~~ 455	~~128~~ 129	~~535,925~~ -
2011	~~1,714~~ 1,719	~~8,152~~ 8,185	~~753~~ 762	~~454~~ 455	~~128~~ 129	~~535,925~~

Biogas Engines – Addition of SCR or NOx Tech

Year	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM-2.5, lb/day	CO2, ton/year
2012	472	8,092	555	464	136	569,999
2014	472	8,092	555	464	136	569,999

Biogas Engines – Replacement with Gas Turbines

Year	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM-2.5, lb/day	CO2, ton/year
2012	5,536	9,205	632	551	1,056	1,260,768
2014	5,536	9,205	632	551	1,056	1,260,768

Biogas Engines – Replacement with Microturbines

Year	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM-2.5, lb/day	CO2, ton/year
2012	4,552	7,948	730	551	792	1,260,768
2014	4,552	7,948	730	551	792	1,260,768

Table C-1 (Concluded)
Operational Emissions from Requirements of PAR 1110.2 Only (i.e, No Secondary Emissions)

Biogas Engines – Replacement of Digester Gas ICE with Gas Turbines Landfill Gas ICE with LNG Plants

Year	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM-2.5, lb/day	CO2, ton/year
2012	4,901	8,090	598	224	883	1,122,319
2014	4,901	8,090	598	224	883	1,122,319

Biogas Engines – Replacement of Digester Gas ICE with Microturbines Landfill Gas ICE with LNG Plants

Year	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM-2.5, lb/day	CO2, ton/year
2012	4,497	7,574	638	224	775	1,122,319
2014	4,497	7,574	638	224	775	1,122,319

Table C-2A
Biogas Diesel Emergency Engine Emissions

Replace ICEs with Gas turbines - Diesel Emergency

Year	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM, lb/day	CO2, ton/year	Mitigated PM lb/day
2012	9.4	7.5	0.96	0.01	0.42	15.8	0.063

Replace ICEs with Microturbines - Diesel Emergency

Year	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM, lb/day	CO2, ton/year	Mitigated PM lb/day
2012	22.6	15.7	2.46	0.02	0.89	22.9	0.133

Replace ICEs LFG w LNG, DG w Turbines - Diesel Emergency

Year	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM, lb/day	CO2, ton/year	Mitigated PM lb/day
2012	9.4	7.5	0.96	0.01	0.42	15.8	0.063

Table C-2A (Concluded)
Biogas Diesel Emergency Engine Emissions

Replace ICEs LFG w LNG, DG w Microturbines - Diesel Emergency

Year	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM, lb/day	CO2, ton/year	Mitigated PM lb/day
2012	22.6	15.7	2.46	0.02	0.89	22.9	0.133

Notes:
Assumed that the emergency generators were needed to provide electricity to compensate for pressure drops caused by add-on control equipment or efficiency losses from the replacement of ICEs with alternative technologies (e.g., gas turbines, microturbines, etc.).
Assumed only digester gas facilities would need emergency generators.
Assumed only 20 percent of digester facilities would use diesel fueled emergency generators
Emission factors from USEPA Emission Standards for Nonroad diesel engines, 40CFR, Part 89 - Control of Emissions from New and In-Use Compression-Ignition Engines
50 hours of operation a year assumed pursuant to Rule 1470.
One hour of operation per test.
ARB has validated diesel particulate filters for stationary ICE as at least 85 percent efficient.

Table C-2B
Biogas Natural Gas Emergency Engine Emissions

Replace ICE with Gas turbines - NG emergency

Year	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM, lb/day	CO2, ton/year
2012	14.5	70.4	6.4	0.28	1.9	218

Replace ICE with Microturbines - NG emergency

Year	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM, lb/day	CO2, ton/year
2012	20.6	99.6	9.1	0.40	2.8	316

Replace ICE LFG w LNG, DG w Turbines - NG emergency

Year	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM, lb/day	CO2, ton/year
2012	14.5	70.4	6.4	0.28	1.9	218

Table C-2B (Concluded)
Biogas Natural Gas Emergency Engine Emissions

Replace ICE LFG w LNG, DG w Microturbines - NG emergency

Year	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM, lb/day	CO2, ton/year
2012	20.6	99.6	9.1	0.40	2.8	316

Notes:
Assumed only digester gas facilities would need emergency generators.
Assumed only 80 percent of digester facilities would use existing natural gas fueled engines as emergency generators.
Existing engine emissions used.
50 hours of operation a year assumed.
One hour of operation per test.

Table C-3
Biogas Power Plant Emissions

Install SCR - Power Plant Emissions - Daily

Year	CO, lb/day	VOC, lb/day	PM, lb/day	CO2, ton/year
2012	50.5	4.1	5.3	15.0

Replace with Microturbines - Power Plant Emissions - Daily

Year	CO, lb/day	VOC, lb/day	PM, lb/day	CO2, ton/year
2012	82.7	6.7	8.6	24.6

Replace LFG w LNG, DG w Turbines - Power Plant Emissions - Daily

Year	CO, lb/day	VOC, lb/day	PM, lb/day	CO2, ton/year
2012	292	23.5	30.5	86.9

Replace LFG w LNG, DG w Microturbines - Power Plant Emissions - Daily

Year	CO, lb/day	VOC, lb/day	PM, lb/day	CO2, ton/year
2012	305	24.6	31.9	90.9

Table C-4
Non-Biogas Effects of Replacing ICE with Electric Motors

Decreased Emissions from Engines

Year	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM, lb/day	CO2, ton/year	Diesel Backup Generator, HP	Diesel Backup Generator Fuel Use, Gal/Yr
2009	432	161	48.9	1.3	15.7	11,781	432	161
2010	856	1,328	137	8.8	50.7	67,378	856	1,328
2011	1,044	2,507	175	14.3	87.9	107,276	1,044	2,507

To determine impacts of electrification on CO2 and criteria pollutant emission, staff has calculated the reduction in engine emissions and the increase in emissions from electrical generation, from boilers that would have to provide thermal energy to replace the thermal energy from an engine in cogeneration use, and from any backup diesel generators installed. The following assumptions were used:

- Engine generator efficiency of 97 percent (engine mechanical output to electrical output).
- Electric motor efficiency of 97 percent.
- For cogeneration engines, 50 percent of the waste heat from the energy is recovered.
- Boiler efficiency of 80 percent.
- Grid power replacing engine power or work is supplied by modern natural gas power plants (80 percent) and by renewable energy sources (20 percent).
- Average power plant efficiency in the district is 36 percent high heating value (HHV) based on USEPA Acid Rain web site data for 2005.
- CO2 from natural gas combustion is 1,009 SCF at 68ºF per million Btu of fuel input (HHV), based on a stoichiometric calculation for methane.
- Boiler criteria pollutant emissions based on 30 ppmvd NOx, and 100 ppmvd CO, corrected to three percent O2.
- Twenty percent of facilities that electrify will install a backup diesel generator. Remainder will convert the natural gas engine to backup use (40 percent), or go without a backup (40 percent).
- Backup diesel efficiency is 33.5 percent HHV.
- Backup generator operated for 50 hours per year.
- Backup generator emissions based on USEPA Tier 3 emission standards for up to 750 bhp and Tier 2 over 750 bhp.
- Diesel fuel specifications are 137,000 Btu per gallon and 88 percent carbon by weight and ultralow sulfur (15 ppmw).
- CO2 reductions from the replacement of non-biogas ICEs with electric motors were assumed to occur over the lifetime of the electric motors (10 years).

Table C-4 (Continued)
Non-Biogas Effects of Replacing ICE with Electric Motors

Power Plant Emissions

Year	CO, lb/day	VOC, lb/day	PM, lb/day	CO2, ton/year
2009	12.2	1.0	1.3	7,272
2010	80.2	6.5	8.4	47,744
2011	126	10.2	26.4	75,098

Diesel Emergency Engine Emissions

Year	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM, lb/day	CO2, ton/year	Mitigated PM, lb/day
2009	10.2	6.8	1.14	0.01	0.39	37	0.058
2010	120	78.8	13.3	0.16	4.5	430	0.68
2011	159	118	16.9	0.24	6.6	1,258	0.99

Natural Gas Emergency Emissions

Year	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM, lb/day	CO2, ton/year
1/1/2009	11.2	5.4	2.0	0.035	0.24	35
7/1/2009	11.3	5.8	2.1	0.039	0.27	51
7/1/2010	55.2	134.1	28.9	0.50	3.4	590
7/1/2011	68.7	262	31.0	0.61	4.2	981

CO2 reduction = baseline CO2 emission less CO2 from fossil power plants producing required power to replace power or work produce by engine less CO2 from increased boiler fuel. Increased boiler fuel = baseline fuel to engine x (1-engine effic) x 0.5 / 0.8 (assumes half of engine waste heat was being utilized by facility and must be replaced by increased boiler fuel at 80% boiler efficiency. Increased boiler fuel also produces NOx (30 ppm@3%O2), CO (100 ppm), SOx (1 grn/100 scf as sulfur) and CO2 emissions.

Grid power replacing engine power or work assumed to be produced 80% by in-basin natural gas plants and 20% by increased power from renewable sources.

Avg. fossil plant effic assumed to be 36% based on USEPA Acid Rain web site. Nat gas consumpt = 3413000 / 0.36 x 0.8 Btu/MWH

Emissions from power plants, based on annual emission reporting x 0.8 (lb/MWH)

NOx, SOx from power plants are capped by RECLAIM.

CO2 ton/MWH = 7.58e6 / 23861 / 16 x 44 / 2000

Selected based on cost calculations - engine categories for which the present-value of the net 10-yr cost of electrification is negative (less than cost of compliance), in order of most negative to least negative on a $/hp basis.

There were 225 engines identified where it would be less to replace the engine with an electric motor than to comply with PAR 1110.2. Of the 225 engines, SCAQMD staff assumed that 75 percent of these engines (169 engines) would be replaced by facility operators.

It was assumed that 20 percent of the engines replaced would need diesel emergency generators, 40 percent of the engines replaced would need natural gas emergency generators, and 40 percent would not need emergency generators.

Table C–5
PAR 1110.2 Cost Effectiveness Calculations

	1	2	3	4	5	6	7	8	9
Fuel	BIOGAS	BIOGAS	BIOGAS	NATURAL GAS	NATURAL GAS	NATURAL GAS	NATURAL GAS	DIESEL	NATURAL GAS
RECLAIM?				RECLAIM	RECLAIM	RECLAIM	RECLAIM	RECLAIM	RECLAIM
BACT?				BACT	BACT	NON-BACT	NON-BACT	BACT	NON-BACT
Rich-Burn or Lean-Burn?				RICH	RICH	RICH	RICH	LEAN	LEAN
=>1000 HP or NOx-Major?	=>1000	<1000	<1000	MAJOR	NON-MAJOR	MAJOR	NON-MAJOR	NON-MAJOR	MAJOR
Need CEMS?		YES	NO						
Number of Engines (Survey Data)	41	7	6	1	16	1	36	6	25
Number of Engines (Total Population)	50	9	7	1	20	1	44	6	31
Average HP (Survey Data)	2,682	614	639	2,000	568	2,068	333	3,043	2,646
New CEMS (Total Population)		2.79							
Fuel Consumption, Btu/Yr (Total Population)	8.81E+12	3.63E+11	2.94E+11	1.31E+11	7.46E+11	1.36E+11	9.62E+11	1.11E+12	5.39E+12
Average NOx Limit, ppmvd @ 15% O2	43.3	38.1	38.1	9.0	15.9	13.8	130.0	50.0	149.4
Average CO Limit, ppmvd @ 15% O2	1225.8	1914.8	1914.8	60.0	98.8	260.2	2000.0	66.0	1896.2
Average VOC Limit, ppmvd @ 15% O2	106.8	245.0	245.0	26.0	106.3	132.0	250.0	22.0	247.9
Baseline NOx, ppmvd @ 15% O2	34.6	41.9	41.9	7.2	82.5	13.8	130.0	55.0	149.4
Baseline CO, ppmvd @ 15% O2	291.3	336.2	336.2	396.0	640.4	1557.9	1327.3	72.6	150.1
Baseline VOC, ppmvd @ 15% O2	47.5	51.5	51.5	18.5	23.5	43.4	40.1	24.2	135.0
Baseline NOx, TPY	596.4	29.7	24.1	1.8	116.7	3.6	237.2	122.1	1,526.3
Baseline CO, TPY	3,052.4	145.2	117.5	60.0	551.4	244.2	1,474.2	98.1	933.0
Baseline VOC, TPY	284.5	12.7	10.3	1.6	11.6	3.9	25.4	18.7	479.8
Controlled NOx (Step 1), ppmvd @ 15% O2	34.6	30.5	38.1	7.2	82.5	13.8	130.0	55.0	149.4
Controlled CO (Step 1), ppmvd @ 15% O2	264.8	305.6	305.6	27.7	58.1	115.8	819.6	66.0	136.4
Controlled VOC (Step 1), ppmvd @ 15% O2	43.2	46.8	46.8	4.9	7.1	11.8	31.5	22.0	122.8
Controlled NOx, TPY	596.4	21.6	21.9	1.8	116.7	3.6	237.2	122.1	1,526.3
Controlled CO, TPY	2,774.9	132.0	106.8	4.2	50.0	18.2	910.4	89.2	848.2
Controlled VOC, TPY	258.6	11.5	9.3	0.4	3.5	1.1	20.0	17.0	436.1
Step 1 (NOx+VOC+CO/7) Reduction, 10-Yr Tons	655	111	46	92	797	351	860	30	557
Controlled NOx (Step 2), ppmvd @ 15% O2	8.8	8.8	11.0	7.2	82.5	13.8	130.0	55.0	149.4
Controlled CO (Step 2), ppmvd @ 15% O2	200.0	250.0	250.0	27.7	58.1	115.8	300.0	66.0	136.4
Controlled VOC (Step 2), ppmvd @ 15% O2	30.0	30.0	30.0	4.9	7.1	11.8	19.1	22.0	30.0
Controlled NOx, TPY	151.5	6.2	6.3	1.8	116.7	3.6	237.2	122.1	1,526.3
Controlled CO, TPY	2,096.0	108.0	87.4	4.2	50.0	18.2	333.2	89.2	848.2
Controlled VOC, TPY	179.7	7.4	6.0	0.4	3.5	1.1	12.1	17.0	106.6
Step 2 (NOx+VOC+CO/7) Reduction, 10-Yr Tons	6,209	230	217	0	0	0	903	0	3,296

Table C-5 (Continued)
PAR 1110.2 Cost Effectiveness Calculations

	10	11	12	13	14	15	16	17	18
Fuel	DIESEL	NATURAL GAS	DIESEL	NATURAL GAS	NATURAL GAS	NATURAL GAS	NATURAL GAS	NATURAL GAS	NATURAL GAS
RECLAIM?	RECLAIM	RECLAIM	RECLAIM	NON-RECLAIM	NON-RECLAIM	NON-RECLAIM	NON-RECLAIM	NON-RECLAIM	NON-RECLAIM
BACT?	NON-BACT	NON-BACT	NON-BACT	BACT	BACT	BACT	BACT	BACT	BACT
Rich-Burn or Lean-Burn?	LEAN	LEAN	LEAN	RICH	RICH	RICH	LEAN	LEAN	LEAN
=>1000 HP or NOx-Major?	MAJOR	NON-MAJOR	NON-MAJOR	=>1000	<1000	<1000	=>1000	<1000	<1000
Need CEMS?					YES	NO		YES	NO
Number of Engines (Survey Data)	6	11	18	28	39	209	16	2	1
Number of Engines (Total Population)	6	14	18	38	53	283	22	3	1
Average HP (Survey Data)	2,213	519	478	1,674	716	286	2,144	880	898
New CEMS (Total Population)					18.13			1.36	
Fuel Consumption, Btu/Yr (Total Population)	8.07E+11	4.78E+11	5.23E+11	4.18E+12	2.49E+12	5.32E+12	3.10E+12	1.73E+11	5.90E+10
Average NOx Limit, ppmvd @ 15% O2	218.0	128.1	516.0	9.8	11.3	11.3	9.3	13.0	13.0
Average CO Limit, ppmvd @ 15% O2	2000.0	1743.9	2000.0	60.4	72.0	72.0	61.6	85.3	85.3
Average VOC Limit, ppmvd @ 15% O2	285.0	235.6	250.0	25.1	30.5	30.5	27.2	37.3	37.3
Baseline NOx, ppmvd @ 15% O2	218.0	128.1	516.0	7.8	58.6	58.6	7.4	23.4	23.4
Baseline CO, ppmvd @ 15% O2	10.8	188.4	221.4	398.6	472.6	472.6	67.8	93.8	93.8
Baseline VOC, ppmvd @ 15% O2	5.1	129.2	106.5	18.6	20.2	20.2	29.9	41.0	41.0
Baseline NOx, TPY	352.0	116.0	539.8	62.1	277.2	591.1	43.7	7.7	2.6
Baseline CO, TPY	10.6	103.8	141.0	1,921.9	1,359.4	2,899.4	242.3	18.8	6.4
Baseline VOC, TPY	2.8	40.7	38.7	51.2	33.2	70.9	61.1	4.7	1.6
Controlled NOx (Step 1), ppmvd @ 15% O2	218.0	128.1	516.0	7.8	9.0	13.6	7.4	13.0	13.0
Controlled CO (Step 1), ppmvd @ 15% O2	9.8	171.3	201.3	27.9	33.1	42.5	61.6	85.3	85.3
Controlled VOC (Step 1), ppmvd @ 15% O2	4.6	117.5	96.8	4.9	5.4	6.1	27.2	37.3	37.3
Controlled NOx, TPY	352.0	116.0	539.8	62.1	42.7	136.7	43.7	4.3	1.5
Controlled CO, TPY	9.6	94.4	128.2	134.3	95.3	260.8	220.3	17.1	5.8
Controlled VOC, TPY	2.6	37.0	35.2	13.5	8.8	21.3	55.6	4.3	1.5
Step 1 (NOx+VOC+CO/7) Reduction, 10-Yr Tons	4	50	54	2,930	4,395	8,810	87	41	14
Controlled NOx (Step 2), ppmvd @ 15% O2	218.0	128.1	516.0	7.8	9.0	13.6	7.4	13.0	13.0
Controlled CO (Step 2), ppmvd @ 15% O2	9.8	171.3	201.3	27.9	33.1	42.5	61.6	85.3	85.3
Controlled VOC (Step 2), ppmvd @ 15% O2	4.6	30.0	30.0	4.9	5.4	6.1	27.2	30.0	30.0
Controlled NOx, TPY	352.0	116.0	539.8	62.1	42.7	136.7	43.7	4.3	1.5
Controlled CO, TPY	9.6	94.4	128.2	134.3	95.3	260.8	220.3	17.1	5.8
Controlled VOC, TPY	2.6	9.4	10.9	13.5	8.8	21.3	55.6	3.4	1.2
Step 2 (NOx+VOC+CO/7) Reduction, 10-Yr Tons	0	276	243	0	0	0	0	8	3

Table C-5 (Continued)
PAR 1110.2 Cost Effectiveness Calculations

	19	20	21	
Fuel	NATURAL GAS	NATURAL GAS	NATURAL GAS	
RECLAIM?	NON-RECLAIM	NON-RECLAIM	NON-RECLAIM	
BACT?	NON-BACT	NON-BACT	NON-BACT	
Rich-Burn or Lean-Burn?	RICH	RICH	RICH	
=>1000 HP or NOx-Major?	=>1000	<1000	<1000	TOTALS
Need CEMS?		YES	NO	
Number of Engines (Survey Data)	5	15	166	655
Number of Engines (Total Population)	7	20	225	859
Average HP (Survey Data)	1,172	665	249	
New CEMS (Total Population)		5.87		28.15
Fuel Consumption, Btu/Yr (Total Population)	5.39E+11	8.74E+11	3.68E+12	4.015E+13
Average NOx Limit, ppmvd @ 15% O2	36.0	45.6	45.6	
Average CO Limit, ppmvd @ 15% O2	2000.0	1956.2	1956.2	
Average VOC Limit, ppmvd @ 15% O2	250.0	277.2	277.2	
Baseline NOx, ppmvd @ 15% O2	28.8	96.7	96.7	
Baseline CO, ppmvd @ 15% O2	1327.3	1560.4	1560.4	
Baseline VOC, ppmvd @ 15% O2	40.1	43.5	43.5	
Baseline NOx, TPY	29.4	160.1	674.5	5,514
Baseline CO, TPY	825.5	1,573.2	6,627.1	22,406
Baseline VOC, TPY	14.2	25.0	105.5	1,298
Controlled NOx (Step 1), ppmvd @ 15% O2	28.8	36.48	54.72	
Controlled CO (Step 1), ppmvd @ 15% O2	609.3	602.9	809.7	
Controlled VOC (Step 1), ppmvd @ 15% O2	27.2	27.0	31.3	
Controlled NOx, TPY	29.4	60.4	381.8	4,418
Controlled CO, TPY	378.9	607.8	3,438.8	10,325
Controlled VOC, TPY	9.6	15.6	76.0	1,038
Step 1 (NOx+VOC+CO/7) Reduction, 10-Yr Tons	684	2,471	7,777	30,816
Controlled NOx (Step 2), ppmvd @ 15% O2	8.8	8.8	13.2	
Controlled CO (Step 2), ppmvd @ 15% O2	200.0	200.0	300.0	
Controlled VOC (Step 2), ppmvd @ 15% O2	15.6	15.6	19.1	
Controlled NOx, TPY	9.0	14.6	92.1	3,586
Controlled CO, TPY	124.4	201.6	1,274.1	6,200
Controlled VOC, TPY	5.5	9.0	46.2	521
Step 2 (NOx+VOC+CO/7) Reduction, 10-Yr Tons	609	1,105	6,287	19,384

Table C-5 (Continued)
PAR 1110.2 Cost Effectiveness Calculations

	1	2	3	4	5	6	7	8	9
Fuel	BIOGAS	BIOGAS	BIOGAS	NATURAL GAS	NATURAL GAS	NATURAL GAS	NATURAL GAS	DIESEL	NATURAL GAS
RECLAIM?				RECLAIM	RECLAIM	RECLAIM	RECLAIM	RECLAIM	RECLAIM
BACT?				BACT	BACT	NON-BACT	NON-BACT	BACT	NON-BACT
Rich-Burn or Lean-Burn?				RICH	RICH	RICH	RICH	LEAN	LEAN
=>1000 HP or NOx-Major?	=>1000	<1000	<1000	MAJOR	NON-MAJOR	MAJOR	NON-MAJOR	NON-MAJOR	MAJOR
Step 1 Eliminate Excess Emissions									
Add CO Analyzer									
Initial Cost, $	0	0	0	19,000	0	19,000	0	0	0
Annual O&M Cost, $	0	0	0	0	0	0	0	0	0
New CEMS									
Initial Cost, $	0	699,492	0	0	0	0	0	0	0
Annual O&M Cost, $	0	190,885	0	0	0	0	0	0	0
Add AFRC									
Initial Cost, $	0	0	140,000	0	0	0	0	0	0
Annual O&M Cost, $	0	0	5,040	0	0	0	0	0	0
Incr Source Testing and I&M Program									
Initial Cost, $	171,443	30,860	24,002	0	68,577	0	150,870	20,573	106,295
Annual O&M Cost, $	313,348	56,403	73,269	0	306,939	0	675,266	37,602	194,276
Total Initial Cost, $	171,443	730,352	164,002	19,000	68,577	19,000	150,870	20,573	106,295
Total Annual O&M Cost, $	313,348	247,288	78,309	0	306,939	0	675,266	37,602	194,276
Present Value of 10-Yr Costs, $	2,816,101	2,817,463	824,928	19,000	2,659,144	19,000	5,850,118	337,932	1,745,983
Step 1 Cost Eff, $ per ton pollutants	**4,299**	**25,270**	**17,745**	**207**	**3,335**	**54**	**6,802**	**11,367**	**3,133**

Table C –5 (Continued)
PAR 1110.2 Cost Effectiveness Calculations

	10	11	12	13	14	15	16	17	18
Fuel	DIESEL	NATURAL GAS	DIESEL	NATURAL GAS	NATURAL GAS	NATURAL GAS	NATURAL GAS	NATURAL GAS	NATURAL GAS
RECLAIM?	RECLAIM	RECLAIM	RECLAIM	NON-RECLAIM	NON-RECLAIM	NON-RECLAIM	NON-RECLAIM	NON-RECLAIM	NON-RECLAIM
BACT?	NON-BACT	NON-BACT	NON-BACT	BACT	BACT	BACT	BACT	BACT	BACT
Rich-Burn or Lean-Burn?	LEAN	LEAN	LEAN	RICH	RICH	RICH	LEAN	LEAN	LEAN
=>1000 HP or NOx-Major?	MAJOR	NON-MAJOR	NON-MAJOR	=>1000	<1000	<1000	=>1000	<1000	<1000
Step 1 Eliminate Excess Emissions									
Add CO Analyzer									
Initial Cost, $	114,000	0	0	722,000	0	0	0	0	0
Annual O&M Cost, $	0	0	0	0	0	0	0	0	0
New CEMS									
Initial Cost, $	0	0	0	0	4,494,928	0	0	291,450	0
Annual O&M Cost, $	0	0	0	0	1,157,627	0	0	72,100	0
Add AFRC									
Initial Cost, $	0	280,000	360,000	0	0	0	0	0	20,000
Annual O&M Cost, $	0	10,080	12,960	0	0	0	0	0	720
Incr Source Testing and I&M Program									
Initial Cost, $		48,004	61,719	0	0	970,367	75,435	10,287	3,429
Annual O&M Cost, $		87,737	112,805	0	0	4,343,190	137,873	18,801	10,467
Total Initial Cost, $	114,000	328,004	421,719	722,000	4,494,928	970,367	75,435	301,736	23,429
Total Annual O&M Cost, $	0	97,817	125,765	0	1,157,627	4,343,190	137,873	90,901	11,187
Present Value of 10-Yr Costs, $	114,000	1,153,583	1,483,179	722,000	14,265,303	37,626,893	1,239,084	1,068,942	117,847
Step 1 Cost Eff, $ per ton pollutants	**28,795**	**22,847**	**27,703**	**246**	**3,246**	**4,271**	**14,236**	**26,137**	**8,471**

Table C-5 (Continued)
PAR 1110.2 Cost Effectiveness Calculations

		19	20	21	
Fuel		NATURAL GAS	NATURAL GAS	NATURAL GAS	
RECLAIM?		NON-RECLAIM	NON-RECLAIM	NON-RECLAIM	
BACT?		NON-BACT	NON-BACT	NON-BACT	
Rich-Burn or Lean-Burn?		RICH	RICH	RICH	
=>1000 HP	or NOx-Major?	=>1000	<1000	<1000	TOTALS
Step 1 Eliminate Excess Emissions					
Add CO Analyzer					
Initial Cost, $		133,000	0	0	1,007,000
Annual O&M Cost, $		0	0	0	0
New CEMS					
Initial Cost, $		0	1,554,923	0	7,040,793
Annual O&M Cost, $		0	417,435	0	1,838,048
Add AFRC					
Initial Cost, $		0	0	0	800,000
Annual O&M Cost, $		0	0	0	28,800
Incr Source Testing and I&M Program					
Initial Cost, $		0	0	771,494	2,513,354
Annual O&M Cost, $		0	0	3,453,066	9,821,043
Total Initial Cost, $		133,000	1,554,923	771,494	11,361,147
Total Annual O&M Cost, $		0	417,435	3,453,066	11,687,891
Present Value of 10-Yr Costs, $		133,000	5,078,070	29,915,374	110,006,945
Step 1 Cost Eff, $ per ton pollutants		**194**	**2,055**	**3,847**	**3,570**

Table C-5 (Continued)
PAR 1110.2 Cost Effectiveness Calculations

	1	2	3	4	5	6	7	8	9
Fuel	BIOGAS	BIOGAS	BIOGAS	NATURAL GAS	NATURAL GAS	NATURAL GAS	NATURAL GAS	DIESEL	NATURAL GAS
RECLAIM?				RECLAIM	RECLAIM	RECLAIM	RECLAIM	RECLAIM	RECLAIM
BACT?				BACT	BACT	NON-BACT	NON-BACT	BACT	NON-BACT
Rich-Burn or Lean-Burn?				RICH	RICH	RICH	RICH	LEAN	LEAN
=>1000 HP or NOx-Major?	=>1000	<1000	<1000	MAJOR	NON-MAJOR	MAJOR	NON-MAJOR	NON-MAJOR	MAJOR
<u>Step 2: Reduce Emissions to NOx/CO/VOC = 11/250/30 ppm @ 15% O2</u>	Gas Cleanup System, SCR and Oxidation Catalyst	Gas Cleanup System, SCR and Oxidation Catalyst	Gas Cleanup System, SCR and Oxidation Catalyst				Upgrade Three-Way Catalyst		Install Oxidation Catalyst
Initial Cost, $	55,201,256	3,733,484	2,903,821				836,264		1,193,872
Annual O&M Cost, $	8,316,509	508,009	395,118				232,115		182,549
Present Value of 10-Yr Costs, $	125,392,596	8,021,083	6,238,620				2,795,312		2,734,583
Step 2 Cost Eff, $ per ton pollutants	**20,197**	**34,940**	**28,756**	**NA**	**NA**	**NA**	**3,094**	**NA**	**830**
Steps 1+ 2 Total Initial Cost, $	55,372,699	4,463,836	3,067,823	19,000	68,577	19,000	987,134	20,573	1,300,167
Steps 1+ 2 Total Annual O&M Cost, $	8,629,858	755,297	473,427	0	306,939	0	907,381	37,602	376,824
Present Value of 10-Yr Costs, $	128,208,697	10,838,546	7,063,548	19,000	2,659,144	19,000	8,645,429	337,932	4,480,565
Steps 1+2 Cost Eff, $ per ton pollutants	**18,679**	**31,778**	**26,813**	**207**	**3,335**	**54**	**4,902**	**11,367**	**1,163**
<u>Alternative Technology</u>				Electrify	Electrify	Electrify	Electrify	Electrify	Electrify
DG Engines (Survey)				0	7	1	5	6	1
DG Engines (Total Population)					9	1	6	6	1
DG Engines--Avg. HP					714	2068	690	3043	3000
Non-DG Engines (Total Population)				1	11		38		30
Non-DG Engines--Avg. HP				2000	454		275		2631
<u>DG Engines:</u>									
(NOx+VOC+CO/7) Reduction, 10-Yr Tons					1,140	415	1,327	1,515	772
Initial Cost, $					1,309,376	390,432	846,867	3,400,883	559,035
Annual O&M Cost, $					104,516	71,687	-37,953	569,812	-108,635
Present Value of 10-Yr Costs, $					2,191,492	995,473	526,547	8,210,095	-357,844

Table C-5 (Continued)
PAR 1110.2 Cost Effectiveness Calculations

	10	11	12	13	14	15	16	17	18
Fuel	DIESEL	NATURAL GAS	DIESEL	NATURAL GAS	NATURAL GAS	NATURAL GAS	NATURAL GAS	NATURAL GAS	NATURAL GAS
RECLAIM?	RECLAIM	RECLAIM	RECLAIM	NON-RECLAIM	NON-RECLAIM	NON-RECLAIM	NON-RECLAIM	NON-RECLAIM	NON-RECLAIM
BACT?	NON-BACT	NON-BACT	NON-BACT	BACT	BACT	BACT	BACT	BACT	BACT
Rich-Burn or Lean-Burn?	LEAN	LEAN	LEAN	RICH	RICH	RICH	LEAN	LEAN	LEAN
=>1000 HP or NOx-Major?	MAJOR	NON-MAJOR	NON-MAJOR	=>1000	<1000	<1000	=>1000	<1000	<1000
<u>Step 2: Reduce Emissions to NOx/CO/VOC = 11/250/30 ppm @ 15% O2</u>		Install Oxidation Catalyst	Install Oxidation Catalyst					Install Oxidation Catalyst	Install Oxidation Catalyst
Initial Cost, $		178,931	230,054					38,342	12,781
Annual O&M Cost, $		22,402	28,802					4,800	1,600
Present Value of 10-Yr Costs, $		368,003	473,147					78,858	26,286
Step 2 Cost Eff, $ per ton pollutants	**NA**	**1,335**	**1,946**	**NA**	**NA**	**NA**	**NA**	**9,446**	**9,257**
Steps 1+ 2 Total Initial Cost, $	114,000	506,935	651,774	722,000	4,494,928	970,367	75,435	340,079	36,210
Steps 1+ 2 Total Annual O&M Cost, $	0	120,219	154,568	0	1,157,627	4,343,190	137,873	95,702	12,787
Present Value of 10-Yr Costs, $	114,000	1,521,586	1,956,325	722,000	14,265,303	37,626,893	1,239,084	1,147,800	144,133
Steps 1+2 Cost Eff, $ per ton pollutants	**28,795**	**4,667**	**6,595**	**246**	**3,246**	**4,271**	**14,236**	**23,308**	**8,605**
<u>Alternative Technology</u>	Electrify	Electrify	Electrify	Electrify	Electrify	Electrify	Electrify	Electrify	Electrify
DG Engines (Survey)	6	6	6	18	16	105	16	0	1
DG Engines (Total Population)	6	7	6	25	22	142	22	0	1
DG Engines--Avg. HP	2213	368	853	1773	771	302	2144		898
Non-DG Engines (Total Population)		7	12	13	31	141		3	0
Non-DG Engines--Avg. HP		701	290	1497	677	270		880	
<u>DG Engines:</u>									
(NOx+VOC+CO/7) Reduction, 10-Yr Tons	3,539	580	3,555	2,522	2,189	5,533	1,210		48
Initial Cost, $	2,499,977	580,251	1,023,792	4,326,469	1,613,478	3,196,932	4,740,122		40,658
Annual O&M Cost, $	-916,897	-15,087	-1,046,832	1,867,548	521,385	2,530,364	1,987,838		52,050
Present Value of 10-Yr Costs, $	-5,238,633	452,916	-7,811,466	20,088,575	6,013,967	24,553,200	21,517,478		479,959

Table C-5 (Continued)
PAR 1110.2 Cost Effectiveness Calculations

	19	20	21	
Fuel	NATURAL GAS	NATURAL GAS	NATURAL GAS	
RECLAIM?	NON-RECLAIM	NON-RECLAIM	NON-RECLAIM	
BACT?	NON-BACT	NON-BACT	NON-BACT	
Rich-Burn or Lean-Burn?	RICH	RICH	RICH	
=>1000 HP or NOx-Major?	=>1000	<1000	<1000	TOTALS
Step 2: Reduce Emissions to NOx/CO/VOC = 11/250/30 ppm @ 15% O2	Upgrade Three-Way Catalyst	Upgrade Three-Way Catalyst	Upgrade Three-Way Catalyst	
Initial Cost, $	262,248	526,200	3,860,550	68,977,804
Annual O&M Cost, $	79,996	154,200	1,048,350	10,974,451
Present Value of 10-Yr Costs, $	937,414	1,827,648	12,708,624	161,602,173
Step 2 Cost Eff, $ per ton pollutants	**1,539**	**1,654**	**2,022**	**8,337**
Steps 1+ 2 Total Initial Cost, $	395,248	2,081,123	4,632,044	80,338,951
Steps 1+ 2 Total Annual O&M Cost, $	79,996	571,635	4,501,416	22,662,342
Present Value of 10-Yr Costs, $	1,070,414	6,905,718	42,623,998	271,609,118
Steps 1+2 Cost Eff, $ per ton pollutants	**828**	**1,931**	**3,031**	**5,410**
Alternative Technology	Electrify	Electrify	Electrify	
DG Engines (Survey)	5	3	14	
DG Engines (Total Population)	7	4	19	284
DG Engines--Avg. HP	1172	930	257	
Non-DG Engines (Total Population)		16	206	509
Non-DG Engines--Avg. HP		598	248	
DG Engines:				
(NOx+VOC+CO/7) Reduction, 10-Yr Tons	1,584	1,133	1,487	28,550
Initial Cost, $	744,245	350,598	430,130	26,053,243
Annual O&M Cost, $	344,681	219,008	287,903	6,431,390
Present Value of 10-Yr Costs, $	3,653,351	2,199,029	2,860,031	80,334,172

Table C-5 (Continued)
PAR 1110.2 Cost Effectiveness Calculations

	1	2	3	4	5	6	7	8	9
Fuel	BIOGAS	BIOGAS	BIOGAS	NATURAL GAS	NATURAL GAS	NATURAL GAS	NATURAL GAS	DIESEL	NATURAL GAS
RECLAIM?				RECLAIM	RECLAIM	RECLAIM	RECLAIM	RECLAIM	RECLAIM
BACT?				BACT	BACT	NON-BACT	NON-BACT	BACT	NON-BACT
Rich-Burn or Lean-Burn?				RICH	RICH	RICH	RICH	LEAN	LEAN
=>1000 HP or NOx-Major?	=>1000	<1000	<1000	MAJOR	NON-MAJOR	MAJOR	NON-MAJOR	NON-MAJOR	MAJOR
Electrify DG Eng's Cost Eff, $ per ton	**NA**	**NA**	**NA**	**NA**	**1,922**	**2,397**	**397**	**5,418**	**-464**
Non-DG Engines:									
(NOx+VOC+CO/7) Reduction, 10-Yr Tons				116	897		3,371		20,469
Initial Cost, $				458,019	1,684,405		4,437,908		17,418,616
Annual O&M Cost, $				9,429	-85,082		-442,620		-5,469,589
Present Value of 10-Yr Costs, $				537,601	966,316		702,199		-28,744,718
Electrify Non-DG Eng's Cost Eff, $ per ton	**NA**	**NA**	**NA**	**4,628**	**1,078**	**NA**	**208**	**NA**	**-1,404**
Incremental Analysis (DG Engines):									
Incremental (NOx+VOC+CO/7) Reduction, 10-Yr Tons					692	64	826	1,486	631
Incremental Present Value of 10-Yr Costs, $					994,877	976,473	-652,375	7,872,163	-502,378
Electrify DG Eng's Incremental Cost Eff, $ per ton	**NA**	**NA**	**NA**	**NA**	**1,438**	**15,254**	**-790**	**5,299**	**-797**
Incremental Analysis (Non-DG Engines):									
Incremental (NOx+VOC+CO/7) Reduction, 10-Yr Tons				25	548		2,108		16,757
Incremental Present Value of 10-Yr Costs, $				518,601	-496,213		-6,764,308		-33,080,749
Electrify Non-DG Incremental Cost Eff, $ per ton	**NA**	**NA**	**NA**	**21,089**	**-905**	**NA**	**-3,209**	**NA**	**-1,974**

Table C-5 (Continued)
PAR 1110.2 Cost Effectiveness Calculations

	10	11	12	13	14	15	16	17	18
Fuel	DIESEL	NATURAL GAS	DIESEL	NATURAL GAS	NATURAL GAS	NATURAL GAS	NATURAL GAS	NATURAL GAS	NATURAL GAS
RECLAIM?	RECLAIM	RECLAIM	RECLAIM	NON-RECLAIM	NON-RECLAIM	NON-RECLAIM	NON-RECLAIM	NON-RECLAIM	NON-RECLAIM
BACT?	NON-BACT	NON-BACT	NON-BACT	BACT	BACT	BACT	BACT	BACT	BACT
Rich-Burn or Lean-Burn?	LEAN	LEAN	LEAN	RICH	RICH	RICH	LEAN	LEAN	LEAN
=>1000 HP or NOx-Major?	MAJOR	NON-MAJOR	NON-MAJOR	=>1000	<1000	<1000	=>1000	<1000	<1000
Electrify DG Eng's Cost Eff, $ per ton	**-1,480**	**780**	**-2,197**	**7,966**	**2,747**	**4,437**	**17,782**	**NA**	**10,053**
<u>Non-DG Engines:</u>									
(NOx+VOC+CO/7) Reduction, 10-Yr Tons		1,116	2,417	1,148	2,753	4,993		146	
Initial Cost, $		1,418,420	1,438,257	2,876,654	3,888,630	10,216,339		308,610	
Annual O&M Cost, $		-192,987	-827,642	169,588	539,101	975,075		66,719	
Present Value of 10-Yr Costs, $		-210,392	-5,547,039	4,307,976	8,438,646	18,445,971		871,722	
Electrify Non-DG Eng's Cost Eff, $ per ton	**NA**	**-189**	**-2,295**	**3,751**	**3,065**	**3,694**	**NA**	**5,972**	**NA**
<u>Incremental Analysis (DG Engines):</u>									
Incremental (NOx+VOC+CO/7) Reduction, 10-Yr Tons	3,536	468	3,378	486	225	866	1,123		31
Incremental Present Value of 10-Yr Costs, $	-5,352,633	-307,877	-8,463,575	19,613,575	92,520	5,673,275	20,278,394		335,827
Electrify DG Eng's Incremental Cost Eff, $ per ton	**-1,514**	**-658**	**-2,505**	**40,389**	**412**	**6,549**	**18,057**	**NA**	**10,836**
<u>Incremental Analysis (Non-DG Engines):</u>									
Incremental (NOx+VOC+CO/7) Reduction, 10-Yr Tons		902	2,297	255	323	850		97	
Incremental Present Value of 10-Yr Costs, $		-971,185	-6,851,256	4,060,976	94,790	-300,997		-276,078	
Electrify Non-DG Incremental Cost Eff, $ per ton	**NA**	**-1,077**	**-2,983**	**15,955**	**294**	**-354**	**NA**	**-2,854**	**NA**

Table C-5(Concluded)
PAR 1110.2 Cost Effectiveness Calculations

		19	20	21	
Fuel		NATURAL GAS	NATURAL GAS	NATURAL GAS	
RECLAIM?		NON-RECLAIM	NON-RECLAIM	NON-RECLAIM	
BACT?		NON-BACT	NON-BACT	NON-BACT	
Rich-Burn or Lean-Burn?		RICH	RICH	RICH	
=>1000 HP	or NOx-Major?	=>1000	<1000	<1000	TOTALS
Electrify DG Eng's Cost Eff, $ per ton		**2,307**	**1,941**	**1,923**	**2,814**
Non-DG Engines:					
(NOx+VOC+CO/7) Reduction, 10-Yr Tons			2,934	15,669	56,030
Initial Cost, $			1,915,837	14,931,788	60,993,484
Annual O&M Cost, $			245,313	1,309,040	-3,703,654
Present Value of 10-Yr Costs, $			3,986,276	25,980,081	29,734,641
Electrify Non-DG Eng's Cost Eff, $ per ton		**NA**	**1,358**	**1,658**	**531**
Incremental Analysis (DG Engines):					
Incremental (NOx+VOC+CO/7) Reduction, 10-Yr Tons		291	132	260	
Incremental Present Value of 10-Yr Costs, $		2,582,937	817,886	-739,329	
Electrify DG Eng's Incremental Cost Eff, $ per ton		**8,882**	**6,196**	**-2,839**	
Incremental Analysis (Non-DG Engines):					
Incremental (NOx+VOC+CO/7) Reduction, 10-Yr Tons			360	2,833	
Incremental Present Value of 10-Yr Costs, $			-1,538,299	-13,044,557	
Electrify Non-DG Incremental Cost Eff, $ per ton		**NA**	**-4,275**	**-4,605**	

PAR 1110.2 Cost Effectiveness Calculations - Preliminary Draft --Notes2

GENERAL:

Cost calculations assume 8000 hrs per year engine operation at full capacity and 31% engine efficiency (HHV).

Results of an engine survey were scaled up to represent total-population estimates based on a 73.5% response rate to the survey (based on number of engines).

Scaling Factors

Biogas engines:	Represented in Calc's =	54	Number found in BCAT search =	66	Factor =	0.818
RECLAIM nat gas engines:	Represented in Calc's =	90	Number found in BCAT search =	111	Factor =	0.811
Other nat gas engines:	Represented in Calc's =	481	Number found in BCAT search =	652	Factor =	0.738
Diesel engines:	Represented in Calc's =	30	Number found in BCAT search =	30	Factor =	1.000
		655		859		

The ten-year present-value calculation assumes a 4% real interest rate (prevailing interest rate less rate of inflation).

For purposes of these calculations, no distinction is made between engines fueled on natural gas, propane or field gas--all are included in "Natural Gas".

NOx, CO and VOC CONCENTRATIONS (Note Concentrations Summary Table at end of this section):

Baseline Emissions

Biogas Engines

Baseline emissions are based on horsepower-weighted averages of NOx limits, landfill gas VOC limits (40 ppm @ 15% O2 as methane), average VOC source test results for digester gas engines based on the survey data, and average CO source test results based on the survey data. In all cases except CEMS-monitored NOx, baseline emissions are assumed to be, on average, 10% above those limits or source test results.

Rich-Burn Engines

For non-RECLAIM and RECLAIM BACT engines with NOx CEMS, it is assumed that the NOx level is maintained on average at 80% of the NOx limit.

For RECLAIM Majors, it is assumed that the NOx level is at the apparent "limit", which was calculated from annual emissions reporting data.

For most rich-burn engines, baseline NOx and CO emissions are based on horsepower-weighted average NOx and CO limits multipled by factors that are based on AQMD compliance test results.

AQMD compliance tests showed that for engines without CEMS, the average ratio of measured NOx to the NOx limit is 5.19 for BACT engines (NOx limit in 8-23 range) and 2.12 for non-BACT engines (NOx limit in 36-59 range).

AQMD compliance tests showed that the average ratio of measured CO to the CO limit follows the relationship R-CO = 6.75 - .00306 x (L - 75), where R-CO = ratio of measured CO to CO limit and L = CO limit, ppmvd @ 15% O2.
If measured CO were capped at 1.2 x L or 0.8 x L, the relationships would have been R-CO(1.2) = 0.590 - .000936 x (L - 75) or R-CO(0.8) = 0.460 - .000807 x (L - 75)

For non-BACT engines in RECLAIM, many NOx limits are above the range of the AQMD compliance data (none tested in this category), and it is assumed that baseline NOx for non-Major sources (no CEMS) in this group is maintained, on average, at the horsepower-weighted NOx limit.

Although compliance testing did not include VOC data, source test data reported in the engine survey showed that VOC levels tend to correspond to roughly the square root of the CO level. The following equations were developed (ppm-15% O2): for non-BACT engines VOC = 1.1 x sq rt (CO) and for BACT engines VOC = 0.93 x sq rt (CO).

Lean-Burn Engines (Excluding Biogas Engines)

Non-BACT engines (all in RECLAIM): Non-CEMS NOx assumed to be at limit on average, and CO and VOC assumed 10% over source test results on average.
For RECLAIM Majors, the NOx level is assumed to be maintained at the reported limit or apparent limit that was calculated based on annual emission reporting.

BACT, non-RECLAIM engines: non-CEMS NOx assumed 1.8 x the NOx limit based on AQMD compliance test results; CO and VOC assumed 10% above average source test results.

BACT RECLAIM engines (Snow Summit diesels, 50 ppm NOx limit, no CEMS): NOx, CO and VOC assumed to be 10% over limits on average.

<u>Controlled Emissions (Step 1)</u>

Step 1 is the increased monitoring requirements that take effect in 2008.

Lean-burn engines: Expected to operate at BACT limits or, in absence of BACT limit, at average source test results.

Rich-burn engines that will have NOx/CO CEMS: it is assumed that both NOx and CO will be maintained on average at 80% of their respective limits.

Rich-burn engines subject to Inspection & Monitoring Plans: it is assumed that both NOx and CO will be, on average, no greater than 20% above their respective limits.

<u>Controlled Emissions (Step 2)</u>

Step 2 is reduction to NOx/CO/VOC = 11/250/30 ppm @ 15% O2, taking effect in 2010 - 2012.

Engines with BACT limits will be unaffected, and engines in RECLAIM will be unaffected regarding NOx.

Engines that will have NOx and/or CO CEMS: it is assumed that the monitored pollutant(s) will be maintained on average at 80% of their respective limits.

Engines subject to Inspection & Monitoring Plans:

Rich-burn:

Lean-burn:

Concentrations Summary Table:

	Baseline			Step 1			Step 2			
	NOx	CO	VOC	NOx	CO	VOC	NOx	CO	VOC	Fuel
Biogas >=1000	0.8 x L	1.1 x S/T	1.1 x S/T	same	S/T	S/T	0.8 x 11	250 or S/T	CO% or 30	Biogas
Biogas <1000, New CEMS	1.1 x L	1.1 x S/T	1.1 x S/T	0.8 x L	S/T	S/T	0.8 x 11	250 or S/T	CO% or 30	Biogas
Biogas <1000, I&M	1.1 x L	1.1 x S/T	1.1 x S/T	L	S/T	S/T	11	250 or S/T	CO% or 30	Biogas
Rich BACT RECL Major	0.8 x L	f(L)	f(CO)	same	f(L)-0.8	f(CO)	same	same	f(CO) or 30	NG
Rich BACT RECL Non-Major	f(L)	f(L)	f(CO)	same	f(L)-1.2	f(CO)	same	same	f(CO) or 30	NG
Rich Non-BACT RECL Major	L	f(L)	f(CO)	same	f(L)-0.8	f(CO)	same	0.8 x 250 or same	f(CO) or 30	NG
Rich Non-BACT RECL Non-Major	L	f(L)	f(CO)	same	f(L)-1.2	f(CO)	same	1.2 x 250 or same	f(CO) or 30	NG
Lean BACT RECL Non-Major Dsl	1.1 x L	1.1 x L	1.1 x L	same	L	L	same	same	same or 30	Dsl
Lean Non-BACT RECL Major	L	1.1 x S/T	1.1 x S/T	same	S/T	S/T	same	250 or S/T	CO% or 30	NG
Lean Non-BACT RECL Major Dsl	L	1.1 x S/T	1.1 x S/T	same	S/T	S/T	same	250 or S/T	CO% or 30	Dsl
Lean Non-BACT RECL Non-Major	L	1.1 x S/T	1.1 x S/T	same	S/T	S/T	same	250 or S/T	CO% or 30	NG
Lean Non-BACT RECL Non-Maj Dsl	L	1.1 x S/T	1.1 x S/T	same	S/T	S/T	same	250 or S/T	CO% or 30	Dsl
Rich BACT >=1000	0.8 x L	f(L)	f(CO)	same	f(L)-0.8	f(CO)	0.8 x (11 or L)	0.8 x (250 or L)	f(CO) or 30	NG
Rich BACT <1000, New CEMS	f(L)	f(L)	f(CO)	0.8 x L	f(L)-0.8	f(CO)	0.8 x (11 or L)	0.8 x (250 or L)	f(CO) or 30	NG
Rich BACT <1000, I&M	f(L)	f(L)	f(CO)	1.2 x L	f(L)-1.2	f(CO)	1.2 x (11 or L)	1.2 x (250 or L)	f(CO) or 30	NG
Lean BACT >=1000	0.8 x L	1.1 x L	1.1 x L	same	L	L	same	same	same or 30	NG
Lean BACT <1000, New CEMS	1.8 x L	1.1 x L	1.1 x L	L	L	L	same	same	same or 30	NG
Lean BACT <1000, I&M	1.8 x L	1.1 x L	1.1 x L	L	L	L	same	same	same or 30	NG
Rich Non-BACT >=1000	0.8 x L	f(L)	f(CO)	same	f(L)-0.8	f(CO)	0.8 x 11	0.8 x 250	f(CO) or 30	NG
Rich Non-BACT <1000, New CEMS	f(L)	f(L)	f(CO)	0.8 x L	f(L)-0.8	f(CO)	0.8 x 11	0.8 x 250	f(CO) or 30	NG
Rich Non-BACT <1000, I&M	f(L)	f(L)	f(CO)	1.2 x L	f(L)-1.2	f(CO)	1.2 x 11	1.2 x 250	f(CO) or 30	NG

Notes:

NOx, CO, VOC TPY CALCULATIONS:

Natural gas: NOx factor is based on 80 ppm NOx @ 3% O2 = 1 lb per MMBtu fuel input (as NO2). For CO, 80 ppm factor becomes 80 x 46 (mol-wt. NO2) / 28 (mol-wt. CO). For VOC (as methane), 80 ppm factor becomes 80 x 46 / 16 (mol-wt. CH4)

Diesel: 80 ppm factor becomes 80 x 8710 (EPA Method 19 dry gas factor for natural gas) / 9190 (EPA Method 19 dry gas factor for diesel).

Biogas: 80 ppm factor becomes 80 x 0.97 to correct for typical 50% CO2 in biogas (resulting in approx. 3% added flue gas volume at 15% O2).

CONTROL COSTS:

Add CO analyzer to existing CEMS

The cost of a CO analyzer ($8,000 to $11,000) was obtained from a CEMS vendor. The cost of installation and reprogramming the DAS is estimated to be about $8000. The impact on span gas costs is expected to be minimal since CO can be added to the NOx span gases at little additional cost. The impact on RATA tests is expected to be minimal.

Total Est. Cost

Install New NOx-CO CEMS

The installed cost and annual cost of a NOx-CO CEMS were obtained from a vendor specializing in that equipment.

	Rich-Burn		Lean-Burn	
	Initial Costs, $	Annual Costs, $	Initial Costs, $	Annual Costs, $
CEMS--NOx/CO for rich-burn engines, NOx-only for lean-burn engines	86,000		78,000	
Switching Valve	5,000		5,000	
Data Aquisition System	25,000		25,000	
Installation	20,000		20,000	
Certification Testing	10,000		10,000	
Startup and Training	25,000		25,000	
Project Management	5,600		5,600	
AQMD Fees	4,000		4,000	
Span Gases		10,000		10,000
RATA		10,000		10,000
Maintenance		15,000		15,000
	180,600	35,000	172,600	35,000
Additional costs for sharing (per engine, AQMD estimates)				
Additional sampling system	15,000		15,000	
Additional installation	10,000		10,000	
Additional DAS programming	5,000		5,000	

Concluded

	Initial Costs, $	Annual Costs, $	Rich-Burn Initial Costs, $	Lean-Burn Annual Costs, $
Additional certification testing	5,000		5,000	
Additional span gases		2,500		2,500
Additional RATA		5,000		5,000
Additional Maintenance		7,500		7,500
	35,000	15,000	35,000	15,000

Install air/fuel ratio controller on a lean burn engine

The installed and operating cost of an air/fuel ratio controller was obtained from a vendor specializing in that equipment.

Installed Cost, $

Operating Cost quarterly changeout of O2 sensor(s)-two sensors @ $90, $/yr

Increased Source Testing and I&M Requirements for Non-CEMS Engines

	Initial Costs, $	Rich-burn	Lean-burn	Lean-burn RECLAIM or w NOx CEMS
Increase source test frequency from every 3 yrs to every 15 months (conservative, for case of highly utilized engine)		1,400	1,400	1,400
AQMD Protocol and Report Evaluation Fees ($278.57 x 2 every 15 mo.)		446	446	446
Source test protocol with every source test (engr labor: 8-hrs initially, then 1 hr every 15 mo., @ $55/hr)	440	28	28	28
I&M Plan (24 hrs engr @ $55)	1,320			
AQMD Plan Evaluation Fee	209			
Initial Parametric Test ($300 test + extra 6 hrs @ $70, 2 hrs engr @ $55, 8 hrs tech @ $35)	1,220			
Alarm ($100 to purchase ennunciator + 4 hrs tech @ $35 to install [AFRC assumed to have output for alarm])	240			
Emission Checks: most engines w/o NOx/CO CEMS--weekly/monthly--18 tests per year @ $300 per test		5,400	5,400	
Lean-burn engines in RECLAIM or with NOx CEMS--4 tests per year @ $300 per test				1,200
Daily inspections (0.25 hr tech time @ $35)		3,194	3,194	3,194
Repeat parametric test whenever O2 sensor is changed (quarterly)		4,880		
	3,429	15,347	10,467	6,267

Install fuel cleanup system, SCR system and oxidation catalyst on biogas-fired engine

	2682 hp		625 hp		Non-Biogas Engine 183 hp	
	Initial Costs, $	Annual Costs, $	Initial Costs, $	Annual Costs, $	Initial Costs, $	Annual Costs, $
Biogas cleanup (siloxane removal) system installed cost, $	353,782		115,926			
Sorbent disposal and replacement, $/yr		73,982		17,240		
Periodic sorbent test		10,000		10,000		
Selective catalytic reduction system installed cost, $	311,257		114,611		43,229	
Startup	10,549		10,549		10,549	
Contingency (10%)	31,126		11,461		4,323	
Total	352,932		136,622		58,101	
Replace catalyst every 3 years		51,876		19,102		7,205
Cost of urea @ $300/ton NH3, $/yr		732		171		50
Oxidation catalyst installed cost,$	29,279		10,562		6,431	
Replace catalyst every 3 years		4,880		1,760		1,072
Cost of parasitic load on engine, $/yr		4,031		939		275
Project management- 160 hrs @ $55	8,800		8,800		8,800	
AQMD application fee	2,300		2,300		2,300	
Performance test	4,000		4,000		4,000	
Annual maintenance cost @ 3% of original equipment cost, $/yr		20,830		7,233		1,490
	1,104,025	166,330	414,832	56,445	137,733	10,091

Installed cost and annual cost for a biogas cleanup system was obtained from a vendor specializing in that equipment.

Installed cost = $1,000,000 x (HP/10,413)^0.766; 850 scfm biogas uses 3400 lb/mo. sorbent @ $1.68/lb disposal and replacement cost plus $10k annual cost of periodic sorbent testing.

The SCR system costs were obtained from a vendor specializing in that equipment--see AQMD staff report

"Proposed Amended Best Available Control Technology (BACT) Guidelines, Part D- Non-Major Polluting Facilities, Regarding Emergency Compression-ignition (Diesel) Engines", April 2003, Appendix H (escalated to 2008 $ @ 3% per year).

The oxidation catalyst installed cost was obtained from a vendor specializing in that equipment.

Parasitic load is estimated to be 0.236% based on 3" H2O pressure loss through the fuel cleanup system and 3" H2O pressure loss through the SCR and oxidation catalysts.
Cost is based on purchase of replacement power at $.0796/kWh.

Upgrade three-way catalyst to meet 11 ppm NOx		2068 hp	1172 hp	665 hp	568 hp	333 hp	249 hp
New catalyst (Installed) (vendor figure)		53,996	34,284	23,130	20,996	15,826	13,978
Project management (16 hrs @ $55)		880	880	880	880	880	880
AQMD application fee		2,300	2,300	2,300	2,300	2,300	2,300
Total		57,176	37,464	26,310	24,176	19,006	17,158
Annual O&M Cost	Replace catalyst every 3 years	17,999	11,428	7,710	6,999	5,275	4,659

Install oxidation catalyst to meet 30 ppm VOC and 250 ppm CO		3265 hp	341 hp
Oxidation catalyst (Installed) (vendor figure + 10% for modifications to ductwork)		35,332	9,601
Project management (16 hrs @ $55)		880	880
AQMD application fee		2,300	2,300
Total		38,512	12,781
Annual O&M Cost	Replace catalyst every 3 years	5,889	1,600

			CEMS Engine	
Eliminate DG engine or replace work engine with electric motor (1000 hp engine)	Remove (DG)	Replace (Non-DG)	Remove (DG)	Replace (Non-DG)
Engine removal (vendor figure) $5,000-$25,000 depends on accessibility	15,000	15,000		
Electric motor (www.automationdirect.com) $7100 @ 200hp, scale with capacity^0.73, includes 8% tax		22,988		
Motor controls and switchgear (AQMD estimate)		10,000		
Installation (vendor figure - about 2X removal cost)		30,000		
Backup generator @ $250/kW	180,905	180,905		
Project management (24 hrs to remove only, 56 hrs to remove and replace@ $55)	1,320	3,080		
	197,225	261,973		
Increased utility demand charge (SCE TOU-8 rate schedule--$194/kW-Yr), $/Yr	140,382	149,200	140,382	149,200
Cost of power (SCE TOU-8 rate schedule--$.0796/kWh ann. avg.), $/Yr	460,801	489,745	460,801	489,745
Avoided cost of fuel @ $0.81 per therm, source/RATA testing and CEMS maintenance, $/Yr	-461,867	-532,987	-478,867	-549,987
Maintenance cost differential--$.01 per hp-hr for ICE vs. negligible cost for motor, $/Yr	-80,000	-80,000	-80,000	-80,000
http://www.distributed-generation.com/Library/PLL%20AEIC.PDF	59,316	25,958	42,316	8,958

Power and fuel calculations assume 31% engine efficiency, 97% motor/generator efficiency, 8000 hrs per year operation.

Emissions from central power plant assumed to be 0.335 CO and .027 VOC (lb/MWh) based on annual emissions reporting. It is also assumed that 80% of marginal grid power is natural gas-based (state law requires grid power to be 20% from renewablr sources starting 2010).

Eliminate DG engine or replace work engine with electric motor (1000 hp engine) (Concluded)	Remove (DG)	Replace (Non-DG)	CEMS Engine Remove (DG)	CEMS Engine Replace (Non-DG)

It is assumed that removal of a natural gas distributed-generation engine increases boiler fuel by (1-0.31) x 0.5 / 0.8 x the engine fuel consumption (50% waste heat utilization, 80% boiler efficiency). Increased emissions from boiler are calculated at 30 ppm NOx and 100 ppm CO, both @ 3% O2 (.0375 and .076 lb/MMBtu, respectively).

Avoided source testing or RATA testing assumes testing triennially @ $3000 for non-CEMS engine and annual testing for CEMS engine.

Avoided CEMS maintenance is $15,000 annual cost.

Annual costs include credit for avoided permit and emission fees @ $955/yr permit fee (or $293 if <500 hp) and $200/ton NOx.

Costs include credits for emission reduction credits (ERC) @ $95,000 per TPY NOx (except in RECLAIM).

Costs for engines in RECLAIM include an annual credit for Reclaim Trading Credits (RTC) @ $4,000 per ton NOx.

Upgrade Biogas to PUC-Quality Pipeline Gas (Replacement of 4860 HP Engine)

	Landfill Gas (DG)	Digester Gas (DG)	Dig. Gas (Non-DG)
Installed Cost, $ (2008)	2,680,000	2,680,000	2,680,000
O&M Cost, $/yr (2008)	410,000	410,000	410,000
Value of PUC gas produced less gas needed for boilers (digester-DG case only), $/yr	1,598,400	760,050	1,598,400
Cost of power production foregone (landfill) or increased power purchase (digester), $/yr	1,026,904	1,026,904	
Cost of engine removal and motor installation, $			58,080
Cost of electric motors and backup generators, $			979,294
Cost of increased demand charge @ $194/kW-yr and purchased power @ $.0796/kWh, $/yr			3,105,273
ICE maintenance, $/yr	-388,800	-388,800	-388,800
CO emissions from increased grid power, tpy	4.36E+00	4.36E+00	4.60E+00
VOC emissions from increased grid power, tpy	3.52E-01	3.52E-01	3.71E-01
NOx emissions from thermal oxidizer, tpy	9.90E-01	9.90E-01	9.90E-01

In digester gas non-DG case, engines are being used to drive compressors. Electrification costs--see above, "replace work engine with electric motor".

Cost and technical information for a biogas upgrade plant were taken from "An Economic Evaluation of Carbon Molecular Sieve Membranes in Landfill Gas Applications", GC Environmental Inc., Media and Process Technology Inc., USC Dept. of Chemical Engineering, Copyright 1999-GC Environmental.

Basis: replacement of a 4860 hp biogas engine using 90,000 scfh biogas @ 45% methane, yielding 33.3 MMBtu/hr PUC gas and 6.6 MMBTU/hr waste gas to thermal oxidizer.

Value of PUC gas calculated at $0.6 per therm (recent wholesale price - US EIA data).

Value of power production foregone (landfill case) calculated at $.0365 per kWh (based on US EIA data for 1999 escalated to 2008 $ @ 3% inflation rate), and value of increased power purchase (digester case) calculated at $.0796 per kWh. Value of avoided engine maintenance calculated at $.01 per hp-hr.

Power plant emissions based on power needed to compress biogas to 400 psi (554 kW) and to replace power produced by engines, @ 0.335 and .027 lb/MWh CO and VOC, resp., from central power plant (NOx capped by RECLAIM), 80% of marginal grid power produced by natural gas plants.

Thermal oxidizer NOx emission calculated based on 30 ppm NOx @ 3% O2.

Possible tax credit (IRS Section 29) not included in this analysis.

Fuel Cell Power Plant for Digester Gas

	Digester Gas (DG)	Dig. Gas (Non-DG)
Average Plant Size, HP	4396	652
ICE kW	3,181	472
Maximum Fuel Cell kW	4,230	627
Fuel Cell Plant Size, kW	4,200	600
Fuel Cell Output, kW	4,200	600
Installed Cost of Fuel Cell Power Plant @ $7000/kW, $	29,400,000	1,500,000
Maintenance (including restacks) @ $.04/kWh, $/yr	1,344,000	192,000
ICE maintenance @ $.01/hp-hr, $/yr	-351,680	-52,160
Cost of electrification, $		196,501
Cost of increased demand charge @ $194/kW-yr and purchased power @ $.0796/kWh, $/yr	-846,557	-81,888
Increased natural gas to boilers @ 50% waste heat utilization and 80% boiler efficiency, MMBtu/yr	16,240	
Cost of increased natural gas to boilers @ $0.81/therm, $/yr	131,547	
CO emissions from grid power increase, tpy	-1.43E-01	-1.38E-02
VOC emissions from grid power increase, tpy	-4.08E-02	-3.94E-03
NOx emissions from fuel cell @ .0017 lb/MWh, tpy	2.86E-02	4.08E-03
VOC emissions from fuel cell @ .007 lb/MWh, tpy	1.18E-01	1.68E-02
NOx emissions from increased boiler fuel @ 30 ppm @ 3% O2, tpy	3.05E-01	

In digester gas non-DG case, engines are being used to drive compressors. Electrification costs--see above, "replace work engine with electric motor".

Costs are for multiple Fuel Cell Energy DFC300MA 300-kW units--plant size based on 31% ICE efficiency, 97% generator efficiency and 40% fuel cell efficiency (average between restacks) (all HHV). Self-Generation Incentive Program provides $4.50 per Watt for new fuel cell biogas generation (applies to Non-DG case).

Plant size based on 31% ICE efficiency, 97% generator efficiency and 40% fuel cell efficiency (average between restacks) (all HHV).

Emissions from grid power are calculated at 0.335 lb/MWh CO and .027 lb/MWh VOC (NOx capped by RECLAIM) and 80% of marginal grid power produced from natural gas plants.

Fuel cell emissions are based on source test results on DFC300MA installation at Palmdale, CA.

Microturbine-Generator Biogas Power Plant

	Landfill Gas (DG)	Digester Gas (DG)	Dig. Gas (Non-DG)
Average Plant Size, HP	6,560	4,396	652
ICE kW	4,747	3,181	472
Maximum MTG kW	4,103	2,749	408
MTG Plant Size, kW	4,160	2,795	455
MTG Plant Output, kW	4,103	2,749	408
Installed Cost, $	8,699,466	7,594,551	455,092
Maintenance @ $.01/kWh, $/yr	328,214	219,943	32,621
ICE maintenance @ $.01/hp-hr, $/yr	-524,800	-351,680	-52,160
Cost of electrification, $			64,903
Cost of increased demand charge @ $194/kW-yr and purchased power @ $.088/kWh, $/yr	535,262	358,691	77,820
Increased natural gas to boilers @ 50% waste heat utilization and 80% boiler efficiency, MMBtu/yr		-9,022	
Cost of increased natural gas to boilers @ $0.81/therm, $/yr		-73,082	
CO emissions from grid power increase, tpy	6.91E-01	4.63E-01	6.86E-02
VOC emissions from grid power increase, tpy	5.57E-02	3.73E-02	5.53E-03
NOx emissions from MTGs @ 9 ppm @ 15% O2, tpy	7.27E+00	4.87E+00	7.23E-01
VOC emissions from MTGs @ 20 ppm @ 3% O2 (as hexane), tpy	1.12E+01	7.53E+00	1.12E+00
NOx emissions from increased boiler fuel @ 30 ppm @ 3% O2, tpy		-1.69E-01	

In digester gas non-DG case, engines are being used to drive compressors. Electrification costs--see above, "replace work engine with electric motor".

Costs are for multiple Capstone 65-kW microturbine-generators (MTGs), incl fuel kits and siloxane-removal skid.

Plant size based on 31% ICE efficiency, 97% generator efficiency and 26% MTG efficiency (all HHV).

MTG cost is $67,000 w/o heat exch. or $80,000 w/ heat exch (digester DG case). Self-Generation Incentive Program provides $1.30 per Watt of new kW (applies to non-DG case).

Installation cost is $35,800 per unit w/o waste heat recovery system, $57,000 per unit w/ waste heat recovery system ("AQMD Microturbine Generator Site Summary Report",

UCI Advanced Power & Energy Program, May 5, 2004) escalated to 2008 $ @ 3% inflation rate.

Cost of gas conditioning skid (information from vendor) is $550/kW @ 500 kW size, $300/kW @ 5 MW size.

Emissions from grid power are calculated at 0.335 lb/MWh CO and .027 lb/MWh VOC (NOx capped by RECLAIM) and 80% of marginal grid power from natural gas plants.

Solar Turbine Mercury 50 Digester Gas Power Plant

	ID 17301	ID 29110
Plant Size, HP	10,413	20,830
ICE kW	7,535	15,073
Maximum Gas Turbine, gross kW	8,641	17,286
Gas Turbine Plant Size, gross kW	9,000	18,000
Gas Turbine Plant Output, kW	8,400	16,800
Installed Cost @ $1200/kW, $	10,800,000	21,600,000
Maintenance @ $.01/kWh, $/yr	691,313	1,382,892
ICE maintenance @ $.01/hp-hr, $/yr	-833,040	-1,666,400
Cost of increased demand charge @ $194/kW-yr and purchased power @ $.0796/kWh, $/yr	-718,596	-1,434,788
Increased natural gas to boilers @ 50% waste heat utilization and 80% boiler efficiency, MMBtu/yr	-4,564	-9,390
Cost of increased natural gas to boilers @ $0.81/therm, $/yr	-36,965	-76,058
CO emissions from grid power increase, tpy	-9.27E-01	-1.85E+00
VOC emissions from grid power increase, tpy	-7.47E-02	-1.49E-01
NOx emissions from gas turbines @ 25 ppm @ 15% O2, tpy	4.25E+01	8.51E+01
VOC emissions from gas turbines @ 20 ppm @ 3% O2 (as hexane), tpy	2.72E+01	4.74E+01
NOx emissions from increased boiler fuel @ 30 ppm @ 3% O2, tpy	-8.56E-02	-1.76E-01

Costs are for multiple Mercury 50 4.2 MW (net) gas turbine-generators, incl fuel compressor (300 psi), sound enclosure, siloxane-removal skid and switchgear.
Plant size based on 31% ICE efficiency, 97% generator efficiency and 34.5% gas turbine-generator gross electrical efficiency (all HHV).
Emissions from grid power are calculated at 0.335 lb/MWh CO and .027 lb/MWh VOC (NOx capped by RECLAIM) and 80% of marginal grid power from natural gas plants.

Electrify Digester Gas-Fueled Compressor Engines

Engine Size, HP	652
Cost of electrification, $	196,501
Cost of increased demand charge @ $194/kW-yr and purchased power @ $.0796/kWh, $/yr	416,592
ICE maintenance @ $.01/hp-hr, $/yr	-52,160
CO emissions from grid power increase, tpy	5.38E-01
VOC emissions from grid power increase, tpy	4.33E-02
NOx emissions from flaring @ .06 lb/MMBtu, tpy	1.28E+00
VOC emissions from flaring @ 10 ppm @ 3% O2 (as methane), tpy	9.31E-02

Emissions from grid power are calculated at 0.335 lb/MWh CO and .027 lb/MWh VOC (NOx capped by RECLAIM) and 80% of marginal grid power from natural gas plants.
Flare emissions are based on NOx BACT and VOC source test data for biogas flares.

Table C-6
Affected Engines

Project - Engines	**2008**	**2009**	**2010**	**2011**	**2012**	**Total**
Increased Source Testing	473					**473**
Inspection & Monitoring	473					**473**
Install Sampling Infrastructure	503					**503**
Install AFRC		34				**34**
Upgrade Three-Way Catalyst			26	50		**76**
Install Oxidation Catalyst			20	9		**29**
Install CEMS - Engine Count		9	28	32		**69**
Install CEMS - CEMS Count		4	10	10		**24**
Install CO Analyzer			34	14		**48**
Install Pretreatment, SCR, Ox Cat or ICE Alternative Technology					66	**66**
Electrified Engines		9	33	128		**170**

Table C-7
Affected Facilities

Project - Facilities	**2008**	**2009**	**2010**	**2011**	**2012**	**Total**
Increased Source Testing	242					**242**
Inspection & Monitoring	242					**242**
Install Sampling Infrastructure	240					**240**
Install AFRC		16				**16**
Upgrade Three-Way Catalyst			15	30		**45**
Install Oxidation Catalyst			5	2		**7**
Install CEMS		4	10	10		**24**
Install CO Analyzer			15	5		**20**
Install Pretreatment, SCR, Ox Cat or ICE Alternative Technology					28	**28**
Facilities with Electrified Engines		4	13	88		**105**

Surveyed facilities are the number of facilities that were included in the surveys.
Total estimated facilities are the surveyed values scaled up to the total number of facilities in the district.
Facilities with electrified engines are the number of facilities that would replace existing non-biogas engines with electric motors instead of complying with PAR 1110.2.

Table C-8
2008 Vehicle Operational Emissions

Description	**Annual No of Trips**[b]	**Daily No of Trips**[b]	**One-way Distance**[c]**, miles**	**NOx, lb/day**	**CO, lb/day**	**VOC, lb/day**	**SOx, lb/day**	**PM10, lb/day**	**PM2.5**[d]**, lb/day**	**CO2, lb/year**
Source Test Related Trips	242	3	30	8.5	2.6	0.67	0.0071	0.42	0.40	61,303
Total				8.5	2.6	0.67	0.0071	0.42	0.40	61,303

Table C-9
2009 Vehicle Operational Emissions

Description	**Annual No of Trips**[b]	**Daily No of Trips**[b]	**One-way Distance**[c]**, miles**	**NOx, lb/day**	**CO, lb/day**	**VOC, lb/day**	**SOx, lb/day**	**PM10, lb/day**	**PM2.5**[d]**, lb/day**	**CO2, lb/year**
Source Test Related Trips	120	1	30	2.83	0.87	0.22	0.002	0.14	0.13	30,398
Diesel Delivery	9	1	30	2.8	0.87	0.22	0.0024	0.14	0.13	2,280
Total				5.7	1.74	0.45	0.005	0.28	0.27	32,678

Table C-10
2010 Vehicle Operational Emissions

Description	Annual No of Trips[b]	Daily No of Trips[b]	One-way Distance[c], miles	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5[d], lb/day	CO2, lb/year
Spent Catalyst Haul Truck	26	2	178	33.59	10.30	2.66	0.028	1.64	1.58	39,079
New Catalyst Delivery Truck	46	3	30	8.49	2.60	0.67	0.007	0.42	0.40	11,653
Source Test Related Trips	121	2	30	5.66	1.74	0.45	0.005	0.28	0.27	30,652
Diesel Delivery	45	1	30	2.83	0.87	0.22	0.002	0.14	0.13	11,399
Total				50.6	15.5	4.0	0.042	2.5	2.4	92,783

Table C-11
2011 Vehicle Operational Emissions

SCR

Description	Annual No of Trips[b]	Daily No of Trips[b]	One-way Distance[c], miles	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5[d], lb/day	CO2, lb/year
Spent Catalyst Haul Truck	30	2	178	33.59	10.30	2.66	0.028	1.64	1.58	45,091
New Catalyst Delivery Truck	46	3	30	8.49	2.60	0.67	0.007	0.42	0.40	11,653
Spent Carbon Haul Truck	92	1	30	2.83	0.87	0.22	0.002	0.14	0.13	23,305
New Carbon Delivery Truck	92	1	30	2.83	0.87	0.22	0.002	0.14	0.13	23,305
Source Test Related Trips	121	2	30	5.66	1.74	0.45	0.005	0.28	0.27	30,652
Ammonia Delivery	19	1	30	2.83	0.87	0.22	0.002	0.14	0.13	4,813
Diesel Delivery	170	2	30	5.66	1.74	0.45	0.005	0.28	0.27	43,064
Total				61.9	19.0	4.9	0.1	126.0	125.9	181,883.8

Gas Turbine

Table C-11 (Continued)
2011 Vehicle Operational Emissions

Description	Annual No of Trips[b]	Daily No of Trips[b]	One-way Distance[c], miles	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5[d], lb/day	CO2, lb/year
Spent Catalyst Haul Truck	30	2	178	33.6	10.3	2.7	0.028	1.6	1.6	225,664
New Catalyst Delivery Truck	46	3	30	8.5	2.6	0.7	0.007	0.4	0.4	7,883
Spent Carbon Haul Truck	92	1	30	2.8	0.9	0.2	0.002	0.1	0.1	23,305
New Carbon Delivery Truck	92	1	30	2.8	0.9	0.2	0.002	0.1	0.1	23,305
Source Test Related Trips	121	1	30	2.8	0.9	0.2	0.002	0.1	0.1	29,132
Diesel Delivery	170	1	30	2.8	0.9	0.2	0.002	0.1	0.1	5,573
Total				53.3	16.5	4.2	0.043	2.4	2.4	314,862

Microturbine

Description	Annual No of Trips[b]	Daily No of Trips[b]	One-way Distance[c], miles	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5[d], lb/day	CO2, lb/year
Spent Catalyst Haul Truck	150	2	178	33.6	10.3	2.7	0.028	1.64	1.6	225,664
New Catalyst Delivery Truck	46	3	30	8.5	2.6	0.7	0.007	0.42	0.4	7,883
Spent Carbon Haul Truck	92	1	30	2.8	0.9	0.2	0.002	0.14	0.1	23,305
New Carbon Delivery Truck	92	1	30	2.8	0.9	0.2	0.002	0.14	0.1	23,305
Source Test Related Trips	121	1	30	2.8	0.9	0.2	0.002	0.14	0.1	29,132
Diesel Delivery	170	1	30	2.8	0.9	0.2	0.002	0.14	0.1	5,573
Total				53.3	16.5	4.2	0.043	2.6	2.4	314,862

Table C-11 (Concluded)
2011 Vehicle Operational Emissions

Gas Turbine/LNG

Description	Annual No of Trips[b]	Daily No of Trips[b]	One-way Distance[c], miles	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5[d], lb/day	CO2, lb/year
Spent Catalyst Haul Truck	150	2	178	33.6	10.3	2.66	0.028	1.6	1.6	225,664
New Catalyst Delivery Truck	31	3	30	8.5	2.6	0.67	0.007	0.42	0.4	7,883
Spent Carbon Haul Truck	92	1	30	2.8	0.9	0.22	0.002	0.14	0.1	23,305
New Carbon Delivery Truck	92	1	30	2.8	0.9	0.22	0.002	0.14	0.1	23,305
Source Test Related Trips	121	2	30	5.7	1.7	0.448	0.005	0.28	0.27	30,652
Diesel Delivery	170	2	30	5.7	1.7	0.448	0.005	0.28	0.27	43,064
LNG Haul Truck	1,360	12	40	45.3	13.9	3.6	0.038	2.2	2.1	459,354
Total				104.4	32.0	8.2	0.09	5.1	4.9	813,228

Microturbine LNG

Description	Annual No of Trips[b]	Daily No of Trips[b]	One-way Distance[c], miles	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5[d], lb/day	CO2, lb/year
Spent Catalyst Haul Truck	150	2	178	33.6	10.3	2.7	0.0282	1.6	1.58	225,664
New Catalyst Delivery Truck	31	3	30	8.5	2.60	0.67	0.0071	0.42	0.40	7,883
Spent Carbon Haul Truck	92	1	30	2.8	0.87	0.22	0.0024	0.14	0.13	23,305
New Carbon Delivery Truck	92	1	30	2.8	0.87	0.22	0.0024	0.14	0.13	23,305
Source Test Related Trips	121	2	30	5.7	1.74	0.45	0.0048	0.28	0.27	30,652
Diesel Delivery	170	2	30	5.7	1.74	0.45	0.0048	0.28	0.27	43,064
LNG Haul Truck	1,360	12	40	45.3	13.9	3.6	0.0380	2.22	2.14	459,354
Total				104.4	32.0	8.2	0.088	5.1	4.9	813,228

There are three possible Class I disposal sites in California: Kettleman City (178 miles from Los Angeles), Buttonwillow (133 miles from Los Angeles), and Westmorland (192 miles from Los Angeles). The intermediate distance, 178 miles per one-way trip, was chosen for this analysis.

Table C-12
2012 Vehicle Operational Emissions

SCR

Description	Annual No of Trips[b]	Daily No of Trips[b]	One-way Distance[c], miles	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5[d], lb/day	CO2, lb/year
Spent Catalyst Haul Truck	123	3	178	50.4	15.45	3.98	0.042	2.47	2.38	185,411
New Catalyst Delivery Truck	183	3	30	8.49	2.60	0.67	0.007	0.42	0.40	46,269
Spent Carbon Haul Truck	184	2	30	5.66	1.74	0.45	0.005	0.28	0.27	46,611
New Carbon Delivery Truck	184	2	30	5.66	1.74	0.45	0.005	0.28	0.27	46,611
Source Test Related Trips	121	2	30	5.66	1.74	0.45	0.005	0.28	0.27	30,652
Ammonia Delivery	38	1	30	2.83	0.87	0.22	0.002	0.14	0.13	9,626
Diesel Delivery	178	2	30	5.66	1.74	0.45	0.005	0.28	0.27	45,091
Total				84	26	6.7	0.071	127	127	410,270

Gas Turbine

Description	Annual No of Trips[b]	Daily No of Trips[b]	One-way Distance[c], miles	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5[d], lb/day	CO2, lb/year
Spent Catalyst Haul Truck	123	3	178	50.4	15.4	4.0	0.042	2.5	2.4	185,411
New Catalyst Delivery Truck	123	3	30	8.5	2.6	0.7	0.007	0.4	0.4	31,249
Spent Carbon Haul Truck	184	2	30	5.7	1.7	0.4	0.005	0.3	0.3	46,611
New Carbon Delivery Truck	184	2	30	5.7	1.7	0.4	0.005	0.3	0.3	46,611
Source Test Related Trips	121	2	30	5.7	1.7	0.4	0.005	0.3	0.3	30,652
Diesel Delivery	178	2	30	5.7	1.7	0.4	0.005	0.3	0.3	45,091
Total				82	25	6.4	0.068	4.0	3.8	385,625

Table C-12 (Continued)
2012 Vehicle Operational Emissions

Microturbine

Description	**Annual No of Trips[b]**	**Daily No of Trips[b]**	**One-way Distance[c], miles**	**NOx, lb/day**	**CO, lb/day**	**VOC, lb/day**	**SOx, lb/day**	**PM10, lb/day**	**PM2.5[d], lb/day**	**CO2, lb/year**
Spent Catalyst Haul Truck	123	3	178	50.4	15.4	4.0	0.042	2.47	2.4	185,411
New Catalyst Delivery Truck	123	3	30	8.5	2.6	0.7	0.007	0.42	0.4	31,249
Spent Carbon Haul Truck	184	2	30	5.7	1.7	0.4	0.005	0.28	0.3	46,611
New Carbon Delivery Truck	184	2	30	5.7	1.7	0.4	0.005	0.28	0.3	46,611
Source Test Related Trips	121	2	30	5.7	1.7	0.4	0.005	0.28	0.3	30,652
Diesel Delivery	178	2	30	5.7	1.7	0.4	0.005	0.28	0.3	45,091
Total				82	25	6.4	0.068	4.0	3.8	385,625

Gas Turbine/LNG

Description	**Annual No of Trips[b]**	**Daily No of Trips[b]**	**One-way Distance[c], miles**	**NOx, lb/day**	**CO, lb/day**	**VOC, lb/day**	**SOx, lb/day**	**PM10, lb/day**	**PM2.5[d], lb/day**	**CO2, lb/year**
Spent Catalyst Haul Truck	123	3	178	50.4	15.4	3.98	0.042	2.47	2.4	185,411
New Catalyst Delivery Truck	123	3	30	8.5	2.6	0.67	0.0071	0.42	0.4	31,249
Spent Carbon Haul Truck	184	2	30	5.7	1.7	0.45	0.0048	0.28	0.3	46,611
New Carbon Delivery Truck	184	2	30	5.7	1.7	0.45	0.0048	0.28	0.3	46,611
Source Test Related Trips	121	2	30	5.7	1.7	0.448	0.0048	0.28	0.27	30,652
Diesel Delivery	178	2	30	5.7	1.7	0.448	0.0048	0.28	0.27	45,091
LNG Haul Truck	1,943	17	40	64.2	19.7	5.1	0.054	3.1	3.0	656,113
Total				146	44.7	11.5	0.12	7.1	6.9	1,041,738

Table C-12 (Concluded)
2012 Vehicle Operational Emissions

Microturbine/LNG

Description	Annual No of Trips[b]	Daily No of Trips[b]	One-way Distance[c], miles	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5[d], lb/day	CO2, lb/year
Spent Catalyst Haul Truck	123	3	178	50.4	15.4	4.0	0.042	2.5	2.38	185,411
New Catalyst Delivery Truck	123	3	30	8.5	2.60	0.67	0.0071	0.42	0.40	31,249
Spent Carbon Haul Truck	184	2	30	5.7	1.74	0.45	0.0048	0.28	0.27	46,611
New Carbon Delivery Truck	184	2	30	5.7	1.74	0.45	0.0048	0.28	0.27	46,611
Source Test Related Trips	121	2	30	5.7	1.74	0.45	0.0048	0.28	0.27	30,652
Diesel Delivery	178	2	30	5.7	1.74	0.45	0.0048	0.28	0.27	45,091
LNG Haul Truck	1,943	17	40	64.2	19.7	5.1	0.054	3.1	3.0	656,113
Total				146	44.7	11.5	0.12	7.1	6.9	1,041,738

There are three possible Class I disposal sites in California: Kettleman City (178 miles from Los Angeles), Buttonwillow (133 miles from Los Angeles), and Westmorland (192 miles from Los Angeles). The intermediate distance, 178 miles per one-way trip, was chosen for this analysis.

Table C-13
2014 Vehicle Operational Emissions

SCR

Description	Annual No of Trips[b]	Daily No of Trips[b]	One-way Distance[c], miles	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5[d], lb/day	CO2, lb/year
Spent Catalyst Haul Truck	163	6	178	101	30.9	7.97	0.085	4.9	4.8	244,822
New Catalyst Delivery Truck	163	6	30	17.0	5.2	1.34	0.014	0.83	0.80	41,262
Spent Carbon Haul Truck	184	2	30	5.7	1.7	0.45	0.005	0.28	0.27	46,611
New Carbon Delivery Truck	184	2	30	5.7	1.7	0.45	0.005	0.28	0.27	46,611
Source Test Related Trips	121	2	30	5.7	1.74	0.45	0.005	0.28	0.27	30,652
Ammonia Delivery	38	1	30	2.8	0.87	0.22	0.002	0.14	0.13	9,626
Diesel Delivery	178	2	30	5.7	1.7	0.45	0.005	0.28	0.27	45,091
Total				143	44	11	0.120	130	130	464,675

Table C-13 (Continued)
2014 Vehicle Operational Emissions

Gas Turbine

Description	**Annual No of Trips[b]**	**Daily No of Trips[b]**	**One-way Distance[c], miles**	**NOx, lb/day**	**CO, lb/day**	**VOC, lb/day**	**SOx, lb/day**	**PM10, lb/day**	**PM2.5[d], lb/day**	**CO2, lb/year**
Spent Catalyst Haul Truck	123	6	178	101	30.9	8.0	0.085	4.9	4.8	185,411
New Catalyst Delivery Truck	123	6	30	17.0	5.2	1.3	0.014	0.8	0.8	31,249
Spent Carbon Haul Truck	184	2	30	5.7	1.7	0.4	0.005	0.3	0.3	46,611
New Carbon Delivery Truck	184	2	30	5.7	1.7	0.4	0.005	0.3	0.3	46,611
Source Test Related Trips	121	2	30	5.7	1.7	0.4	0.005	0.3	0.3	30,652
Diesel Delivery	178	2	30	5.7	1.7	0.4	0.005	0.3	0.3	45,091
Total				140	43.0	11	0.12	6.9	6.6	385,625

Microturbine

Description	**Annual No of Trips[b]**	**Daily No of Trips[b]**	**One-way Distance[c], miles**	**NOx, lb/day**	**CO, lb/day**	**VOC, lb/day**	**SOx, lb/day**	**PM10, lb/day**	**PM2.5[d], lb/day**	**CO2, lb/year**
Spent Catalyst Haul Truck	123	6	178	101	30.9	8.0	0.085	4.9	4.8	185,411
New Catalyst Delivery Truck	123	6	30	17.0	5.2	1.3	0.014	0.83	0.80	31,249
Spent Carbon Haul Truck	184	2	30	5.7	1.7	0.4	0.005	0.28	0.27	46,611
New Carbon Delivery Truck	184	2	30	5.7	1.7	0.4	0.005	0.28	0.27	46,611
Source Test Related Trips	121	2	30	5.7	1.7	0.4	0.005	0.28	0.27	30,652
Diesel Delivery	178	2	30	5.7	1.7	0.4	0.005	0.28	0.27	45,091
Total				140	43.0	11.1	0.118	6.9	6.6	385,625

Table C-13 (Continued)
2014 Vehicle Operational Emissions

Gas Turbine/LNG

Description	Annual No of Trips[b]	Daily No of Trips[b]	One-way Distance[c], miles	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5[d], lb/day	CO2, lb/year
Spent Catalyst Haul Truck	123	6	178	101	30.9	7.97	0.085	4.93	4.8	185,411
New Catalyst Delivery Truck	123	6	30	17.0	5.2	1.34	0.014	0.83	0.80	31,249
Spent Carbon Haul Truck	184	2	30	5.7	1.7	0.45	0.005	0.28	0.27	46,611
New Carbon Delivery Truck	184	2	30	5.7	1.7	0.45	0.005	0.28	0.27	46,611
Source Test Related Trips	121	2	30	5.7	1.7	0.448	0.005	0.28	0.27	30,652
Diesel Delivery	178	2	30	5.7	1.7	0.448	0.005	0.28	0.27	45,091
LNG Haul Truck	3,885	33	40	125	38.2	9.8	0.105	6.10	5.9	1,312,227
Total				265	81.2	20.9	0.22	13.0	12.5	1,697,851

Table C-13 (Concluded)
2014 Vehicle Operational Emissions

Microturbine/LNG

Description	Annual No of Trips[b]	Daily No of Trips[b]	One-way Distance[c], miles	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5[d], lb/day	CO2, lb/year
Spent Catalyst Haul Truck	123	6	178	101	30.9	8.0	0.085	4.9	4.8	185,411
New Catalyst Delivery Truck	123	6	30	17.0	5.21	1.34	0.014	0.83	0.80	31,249
Spent Carbon Haul Truck	184	2	30	5.7	1.74	0.45	0.005	0.28	0.27	46,611
New Carbon Delivery Truck	184	2	30	5.7	1.74	0.45	0.005	0.28	0.27	46,611
Source Test Related Trips	121	2	30	5.7	1.74	0.45	0.005	0.28	0.27	30,652
Diesel Delivery	178	2	30	5.7	1.74	0.45	0.005	0.28	0.27	45,091
LNG Haul Truck	3,885	33	40	125	38.2	9.8	0.105	6.1	5.9	1,312,227
Total				265	81.2	20.9	0.222	13.0	12.5	1,697,851

There are three possible Class I disposal sites in California: Kettleman City (178 miles from Los Angeles), Buttonwillow (133 miles from Los Angeles), and Westmorland (192 miles from Los Angeles). The intermediate distance, 178 miles per one-way trip, was chosen for this analysis.

Table C-14
Summary of Operational Emissions

SCR - Total Operational Emissions

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5 lb/day	CO2, ton/year
2005 Baseline	9,195	54,243	2,493	551	877	875	1,250,047
2008	~~8,999~~ 9,004	~~53,867~~ 53,900	~~2,458~~ 2,467	~~544~~ 545	~~872~~ 873	~~870~~ 871	1,227,230
2009	~~6,410~~ 6,415	~~22,399~~ 22,432	~~1,790~~ 1,799	~~543~~ 544	~~858~~ 859	~~856~~ 857	1,231,763
2010	~~5,823~~ 5,828	~~17,295~~ 17,328	~~1,281~~ 1,290	~~534~~ 535	~~837~~ 838	~~835~~ 836	1,207,871
2011	~~5,345~~ 5,350	~~13,475~~ 13,508	~~1,207~~ 1,216	~~528~~ 529	~~821~~ 822	~~819~~ 820	1,196,652
2012	4,125	13,423	1,011	538	830	829	1,231,595
2014	4,184	13,441	1,015	538	833	831	1,231,622

Table C-14 (Continued)
Summary of Operational Emissions

Gas Turbines - Total Operational Emissions

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5 lb/day	CO2, ton/year
2005 Baseline	9,195	54,243	2,493	551	877	875	1,250,047
2008	~~8,999~~ 9,004	~~53,867~~ 53,900	~~2,458~~ 2,467	~~544~~ 545	~~872~~ 873	~~870~~ 871	1,227,230
2009	~~6,410~~ 6,415	~~22,399~~ 22,432	~~1,790~~ 1,799	~~543~~ 544	~~858~~ 859	~~856~~ 857	1,231,763
2010	~~5,823~~ 5,828	~~17,295~~ 17,328	~~1,281~~ 1,290	~~534~~ 535	~~837~~ 838	~~835~~ 836	1,207,871
2011	~~5,339~~ 5,344	~~13,473~~ 13,506	~~1,206~~ 1,215	~~528~~ 529	~~821~~ 822	~~819~~ 820	1,196,720
2012	4,825	7,357	533	538	1,016	1,014	1,231,271
2014	4,884	7,375	537	538	1,019	1,017	1,231,271

Microturbines - Total Operational Emissions

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5 lb/day	CO2, ton/year
2005 Baseline	9,195	54,243	2,493	551	877	875	1,250,047
2008	~~8,999~~ 9,004	~~53,867~~ 53,900	~~2,458~~ 2,467	~~544~~ 545	~~872~~ 873	~~870~~ 871	1,227,230
2009	~~6,410~~ 6,415	~~22,399~~ 22,432	~~1,790~~ 1,799	~~543~~ 544	~~858~~ 859	~~856~~ 857	1,231,763
2010	~~5,823~~ 5,828	~~17,295~~ 17,328	~~1,281~~ 1,290	~~534~~ 535	~~837~~ 838	~~835~~ 836	1,207,871
2011	~~5,339~~ 5,344	~~13,473~~ 13,506	~~1,206~~ 1,215	~~528~~ 529	~~821~~ 822	~~819~~ 820	1,196,720
2012	3,860	6,169	638	538	757	756	1,231,385
2014	3,919	6,187	643	538	760	758	1,231,385

Table C-14 (Concluded)
Summary of Operational Emissions

Gas Turbines/LNG - Total Operational Emissions

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5 lb/day	CO2, ton/year
2005 Baseline	9,195	54,243	2,493	551	877	875	1,250,047
2008	~~8,999~~ 9,004	~~53,867~~ 53,900	~~2,458~~ 2,467	~~544~~ 545	~~872~~ 873	~~870~~ 871	1,227,230
2009	~~6,440~~ 6,445	~~23,215~~ 23,248	~~1,814~~ 1,823	~~543~~ 544	~~860~~ 861	~~858~~ 859	1,232,969
2010	~~5,823~~ 5,828	~~17,295~~ 17,328	~~1,281~~ 1,290	~~534~~ 535	~~837~~ 838	~~835~~ 836	1,207,871
2011	~~5,390~~ 5,395	~~13,489~~ 13,522	~~1,210~~ 1,219	~~528~~ 529	~~823~~ 824	~~821~~ 822	1,196,970
2012	4,254	6,503	523	211	872	870	1,093,223
2014	4,373	6,540	533	211	878	876	1,093,551

Microturbines/LNG - Total Operational Emissions

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5 lb/day	CO2, ton/year
2005 Baseline	9,195	54,243	2,493	551	877	875	1,250,047
2008	~~8,999~~ 9,004	~~53,867~~ 53,900	~~2,458~~ 2,467	~~544~~ 545	~~872~~ 873	~~870~~ 871	1,227,230
2009	~~6,410~~ 6,415	~~22,399~~ 22,432	~~1,790~~ 1,799	~~543~~ 544	~~858~~ 859	~~856~~ 857	1,231,763
2010	~~5,823~~ 5,828	~~17,295~~ 17,328	~~1,281~~ 1,290	~~534~~ 535	~~837~~ 838	~~835~~ 836	1,207,871
2011	~~5,390~~ 5,395	~~13,489~~ 13,522	~~1,210~~ 1,219	~~528~~ 529	~~823~~ 824	~~821~~ 822	1,196,970
2012	3,870	6,038	569	211	767	765	1,093,331
2014	3,989	6,075	578	211	773	771	1,093,659

Table C-15
Construction of an LNG Plant – Grading

Construction Activity			
Three Acre Site	Grading	130,000	Square Feet[a]

Site Preparation Schedule - 6 days[a]

Equipment Type[a,b]	No. of Equipment	hr/day	Crew Size
Scrapers	1	8.0	5
Graders	1	8.0	
Tractors/Loaders/Backhoes	1	7.0	

Construction Equipment Emission Factors						
	CO	**NOx**	**PM10**	**VOC**	**SOx**	**CO2**
Equipment Type[c]	lb/hr	lb/hr	lb/hr			
Scrapers	1.525	3.399	0.147	0.368	0.003	262.5
Graders	0.671	1.720	0.089	0.206	0.001	132.7
Tractors/Loaders/Backhoes	0.414	0.830	0.064	0.131	0.001	66.8

Fugitive Dust Clearing Parameters - Scraping						
Silt Content[d]	**Mean Vehicle Weight[e]**	**Vehicle Miles Traveled[f]**				
	ton					
6.9	88.73	0.43				

Fugitive Dust Stockpiling Parameters						
Silt Content[d]	**Precipitation Days[g]**	**Mean Wind Speed Percent[h]**	**TSP Fraction**	**Area[i] (acres)**		
6.9	10	100	0.5	0.11		

Table C-15 (Continued)
Construction of an LNG Plant – Grading

Fugitive Dust Material Handling

Aerodynamic Particle Size Multiplier[j]	Mean Wind Speed[k]	Moisture Content[f]	Dirt Handled[a]	Dirt Handled[l]
	mph		cy	lb/day
0.35	10	7.9	778	324,167

Construction Vehicle (Mobile Source) Emission Factors

	CO	NOx	PM10	VOC	SOx	CO2
	lb/mile	lb/mile	lb/mile	lb/mile	lb/mile	lb/mile
Heavy-Duty Truck[m]	0.01446237	0.04718166	0.00230900	0.00372949	0.00003962	4.221844935
Passenger Vehicle	0.01155158	0.00121328	0.00008447	0.00118234	0.00001078	1.106722361

Construction Worker Number of Trips and Trip Length

Vehicle	No. of One-Way Trips/Day	One WayTrip Length (miles)
Haul Truck[n]	5	30
Water Truck[o]	3	4.2
Worker Vehicles	5	10

Incremental Increase in Onsite Combustion Emissions from Construction Equipment

Equation: Emission Factor (lb/hr) x No. of Equipment x Work Day (hr/day) = Onsite Construction Emissions (lb/day)

	CO	NOx	PM10	VOC	SOx	CO2
Equipment Type	lb/day	lb/day	lb/day	lb/day	lb/day	lb/day
Scrapers	12.20	27.19	1.17	2.94	0.02	2100.0
Graders	5.37	13.76	0.71	1.64	0.01	1061.9
Tractors/Loaders/Backhoes	2.90	5.81	0.45	0.91	0.01	467.6
Total	**20.5**	**46.8**	**2.3**	**5.5**	**0.04**	**3629.6**

Table C-15 (Continued)
Construction of an LNG Plant – Grading

Incremental Increase in Fugitive Dust Emissions from Construction Operations

Equations:

Scraping[p]: PM10 Emissions (lb/day) = 1.5 x (silt content/12)$^{0.9}$ x (mean vehicle weight)$^{0.45}$ x VMT x (1 - control efficiency)

Storage Piles[q]: PM10 Emissions (lb/day) = 1.7 x (silt content/1.5) x ((365-precipitation days)/235) x wind speed percent/15 x TSP fraction x Area) x (1 - control efficiency)

Material Handling[r]: PM10 Emissions (lb/day) = (0.0032 x aerodynamic particle size multiplier x (wind speed (mph)/5)$^{1.3}$/(moisture content/2)$^{1.4}$ x dirt handled (lb/day)/2,000 (lb/ton) (1 - control efficiency)

Description	**Control Efficiency** %	**PM10[s]** lb/day
Scraping	68	0.58
Storage Piles	68	1.39
Material Handling	68	0.02
Total		**1.99**

Incremental Increase in Onsite Combustion Emissions from Onroad Mobile Vehicles

Equation: Emission Factor (lb/mile) x No. of One-Way Trips/Day x 2 x Trip length (mile) = Mobile Emissions (lb/day)

Vehicle	**CO** lb/day	**NOx** lb/day	**PM10** lb/day	**VOC** lb/day	**SOx** lb/day	**CO2** lb/day
Haul Truck	4.34	14.2	0.69	1.12	0.01	1,267
Water Truck	0.36	1.19	0.06	0.09	0	106
Worker Vehicles	1.16	0.12	0.01	0.12	0	111
Total	**5.86**	**15.46**	**0.76**	**1.33**	**0.01**	**1,484**

Table C- 15 (Continued)
Construction of an LNG Plant – Grading

Total Incremental Localized Emissions from Construction Activities						
	CO	**NOx**	**PM10**	**VOC**	**SOx**	**CO2**
Sources	lb/day	lb/day	lb/day	lb/day	lb/day	lb/day
Daily Emissions	**26.3**	**62.2**	**5.1**	**6.8**	**0.1**	**5,113**
Annual Emissions	**158.0**	**373.4**	**30.5**	**41.0**	**0.3**	**30,679**

Combustion and Fugitive Summary	**PM2.5 Fraction**[t]	**PM10** lb/day	**PM2.5** lb/day	**Percentage Contribution**
Combustion (Offroad)	0.92	2.3	2.1	65.0%
Combustion (Onroad)	0.96	0.76	0.74	22.3%
Fugitive	0.21	2	0.4	12.7%
Daily Emissions		**5.1**	**3.3**	
Annual Emissions		**30.5**	**19.8**	

Notes:

a) SCAQMD, estimated from survey data, Sept 2004

b) Equipment name must match CARB Off-Road Model (see Off-Road Model EF worksheet) equipment name for sheet to look up EFs automatically.

c) SCAB values provided by the ARB, May 2007. Assumed equipment is diesel fueled.

d) USEPA, AP-42, July 1998, Table 11.9-3 Typical Values for Correction Factors Applicable to the Predictive Emission Factor Equations

e) Mean vehicle weight (120,460 pound empty with a 75,000 pound capacity) estimated from 631G Model Scraper Caterpillar Performance Handbook, Edition 33. Scraper in the same horsepower range (450-490 hp) as the composite ARB emission factors.

f) Caterpillar G31G has a 11.5 foot wide blade, with an assumed 2 foot overlap (9.5 foot wide). Vehicle miles traveled (VMT) = (130,000 sq ft/9.5 foot x mile/5,280 ft)/6 days = 0.43 miles

g) Table A9-9-E2, SCAQMD CEQA Air Quality Handbook, 1993

h) Mean wind speed percent - percent of time mean wind speed exceeds 12 mph. At least one meteorological site recorded wind speeds greater than 12 mph over a 24-hour period in 1981.

i) Assumed storage piles are 0.11 acres in size

j) USEPA, AP-42, Jan 1995, Section 13.2.4 Aggregate Handling and Storage Piles, p 13.2.4-3 Aerodynamic particle size multiplier for < 10 µm

k) Mean wind speed - maximum of daily average wind speeds reported in 1981 meteorological data.

l) Assuming 778 cubic yards of dirt handled [(778 cyd x 2,500 lb/cyd)/ days = 324,167 lb/day]

m) CARB, EMFAC2007 (version 2.3) Burden Model, Winter 2007, 75 F, 40% RH: EF, lb/yr = (EF, ton/yr x 2,000 lb/ton)/VMT

Table C-15 (Concluded)
Construction of an LNG Plant – Grading

n) Assumed 30 cubic yd truck capacity for 778 cyd of dirt [(778 cy x truck/30 cy)/6 days = 5 one-way truck trips/day]. Assumed haul truck travels 0.1 miles through facility. Multiple trucks may be used.
o) Assumed six foot wide water truck traverses over 130,000 square feet of disturbed area
p) USEPA, AP-42, July 1998, Equation 1b and Table 13.2.2-2, AP-42, December 2003. Also see comment g of Table 11.9-1
q) USEPA, AP-42, Jan 1995, Section 13.2.4 Aggregate Handling and Storage Piles, Equation 1
r) USEPA, Fugitive Dust Background Document and Technical Information Document for Best Available Control Measures, Sept 1992, EPA-450/2-92-004, Equation 2-12
s) Includes watering at least three times a day per Rule 403 (68% control efficiency).
t) ARB's CEIDARS database PM2.5 fractions - construction dust category for fugitive and diesel vehicle exhaust category for combustion.

Table C-16
Construction of an LNG Plant – Paving

	Construction Activity
Three Acre Site	Architectural Coating and Asphalt Paving of Parking Lot

Construction Schedule -	**10**	**days[a]**	
Equipment Type[a,b]	**No. of Equipment**	**hr/day**	**Crew Size**
Pavers	1	8.00	8
Paving Equipment	1	8.00	
Rollers	2	8.00	
Cement and Mortar Mixers	1	3.00	
Tractors/Loaders/Backhoes	1	8.00	

Construction Equipment Combustion Emission Factors

	CO	**NOx**	**PM10**	**VOC**	**SOx**	**CO2**
Equipment Type[c]	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr
Pavers	0.600	1.129	0.080	0.206	0.001	77.9
Paving Equipment	0.469	1.033	0.071	0.156	0.001	69.0
Rollers	0.442	0.907	0.063	0.141	0.001	67.1
Cement and Mortar Mixers	0.046	0.069	0.005	0.012	0.000	7.2
Tractors/Loaders/Backhoes	0.414	0.830	0.064	0.131	0.001	66.8

Construction Vehicle (Mobile Source) Emission Factors

	CO	**NOx**	**PM10**	**VOC**	**SOx**	**CO2**
	lb/mile	lb/mile	lb/mile	lb/mile	lb/mile	lb/mile
Heavy-Duty Truck[d]	0.01446237	0.04718166	0.00230900	0.00372949	0.00003962	4.221844935

Table C-16 (Continued)
Construction of an LNG Plant – Paving

Construction Worker Number of Trips and Trip Length		
Vehicle	**No. of One-Way Trips/Day**	**Trip Length (miles)**
Delivery Truck[e]	9	20
Water Truck[f]	3	4.5

Incremental Increase in Onsite Combustion Emissions from Construction Equipment

Equation: Emission Factor (lb/hr) x No. of Equipment x Work Day (hr/day) = Onsite Construction Emissions (lb/day)

	CO	**NOx**	**PM10**	**VOC**	**SOx**	**CO2**
Equipment Type	lb/day	lb/day	lb/day	lb/day	lb/day	lb/day
Pavers	4.80	9.03	0.64	1.65	0.01	623.49
Paving Equipment	3.75	8.27	0.57	1.24	0.01	551.62
Rollers	7.07	14.52	1.01	2.26	0.01	1,072.88
Cement and Mortar Mixers	0.14	0.21	0.01	0.04	0.00	21.74
Tractors/Loaders/Backhoes	3.31	6.64	0.51	1.05	0.01	534.46
Total	**19.1**	**38.7**	**2.7**	**6.2**	**0.0**	**2,804.19**

Incremental Increase in Onsite Combustion Emissions from Onroad Mobile Vehicles

Equation: Emission Factor (lb/mile) x No. of One-Way Trips/Day x 2 x Trip length (mile) = Mobile Emissions (lb/day)

	CO	**NOx**	**PM10**	**VOC**	**SOx**	**CO2**
Vehicle	lb/day	lb/day	lb/day	lb/day	lb/day	lb/day
Delivery Truck	5.21	16.99	0.831	1.343	0.014	1519.864
Water Truck	0.39	1.27	0.06	0.1	0	113.99
Total	**5.60**	**18.26**	**0.89**	**1.44**	**0.01**	**1633.85**

Table C-16 (Concluded)
Construction of an LNG Plant – Paving

Total Incremental Combustion Emissions from Construction Activities

Sources	CO lb/day	NOx lb/day	PM10 lb/day	VOC lb/day	SOx lb/day	CO2 lb/day
Daily Emissions	**24.7**	**56.9**	**3.6**	**7.7**	**0.1**	**4,438**
Annual Emissions	**246.7**	**569.3**	**36.3**	**76.8**	**0.540**	**44,380**

Combustion and Fugitive Summary	PM2.5 Fraction[g]	PM10 lb/day	PM2.5 lb/day
Combustion (Offroad)	0.92	2.7	2.5
Combustion (Onroad)	0.96	0.89	0.86
Fugitive	0.21	0	0.0
Daily Emissions		**3.6**	**3.4**
Annual Emissions		**36.3**	**33.8**

Notes:

a) SCAQMD, estimated from survey data, Sept 2004

b) Equipment name must match CARB Off-Road Model (see Off-Road Model EF worksheet) equipment name for sheet to look up EFs automatically.

c) SCAB values provided by the ARB, May 2007. Assumed equipment is diesel fueled.

d) CARB, EMFAC2007 (version 2.3) Burden Model, Winter 2007, 75 F, 40% RH: EF, lb/yr = (EF, ton/yr x 2,000 lb/ton)/VMT

e) Assumed haul truck travels 0.1 miles through facility

f) Assumed six foot wide water truck traverses over 140,000 square feet of disturbed area

t) ARB's CEIDARS database PM2.5 fractions - construction dust category for fugitive and diesel vehicle exhaust category for combustion.

Table C-17
Construction of an LNG Plant – Structure Construction

Construction Activity
Internal Combustion Engine and Equipment Installation

Construction Schedule 95 **days**[a]

Equipment Type[a,b]	No. of Equipment	hr/day	Crew Size
Cranes	2	7.0	15
Rubber Tired Loaders	2	7.0	
Forklifts	2	7.0	
Welder	3	7.0	
Generator Sets	3	7.0	

Construction Equipment Combustion Emission Factors

	CO	NOx	PM10	VOC	SOx	CO2
Equipment Type[c]	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr
Cranes	0.637	1.695	0.075	0.188	0.001	128.7
Rubber Tired Loaders	0.555	1.382	0.077	0.173	0.001	108.6
Forklifts	0.250	0.643	0.035	0.086	0.001	54.4

Construction Vehicle (Mobile Source) Emission Factors

	CO	NOx	PM10	VOC	SOx	CO2
	lb/mile	lb/mile	lb/mile	lb/mile	lb/mile	lb/mile
Heavy-Duty Truck[d]	0.01446237	0.04718166	0.00230900	0.00372949	0.00003962	4.222
Passenger Vehicle	0.01155158	0.00121328	0.00008447	0.00118234	0.00001078	1.107

Table C-17 (Continued)
Construction of an LNG Plant – Structure Construction (Continued)

Number of Trips and Trip Length

Vehicle	**No. of One-Way Trips/Day**	**One Way Trip Length (miles)**
Haul Trucks[e]	4	20
Worker Vehicles	15	10

Incremental Increase in Onsite Idling Emissions from Onroad Mobile Vehicles

Equation: Emission Factor (lb/hr) x No. of Equipment x Work Day (hr/day) = Onsite Construction Emissions (lb/day)

	CO	**NOx**	**PM10**	**VOC**	**SOx**	**CO2**
Equipment Type	lb/day	lb/day	lb/day	lb/day	lb/day	lb/day
Cranes	8.91	23.73	1.06	2.63	0.019	1801.428
Rubber Tired Loaders	7.77	19.35	1.08	2.42	0.017	1520.591
Forklifts	3.49	9.00	0.48	1.21	0.008	761.541
Welder	0.00	0.00	0.00	0.00	0.000	0.000
Generator Sets	0.00	0.00	0.00	0.00	0.000	0.000
Total	**20.18**	**52.08**	**2.62**	**6.26**	**0.045**	**4,084**

Incremental Increase in Onsite Combustion Emissions from Onroad Mobile Vehicles

Equation: Emission Factor (lb/mile) x No. of One-Way Trips/Day x 2 x Trip length (mile) = Mobile Emissions (lb/day)

	CO	**NOx**	**PM10**	**VOC**	**SOx**	**CO2**
Vehicle	lb/day	lb/day	lb/day	lb/day	lb/day	lb/day
Flatbed Trucks	2.314	7.549	0.3694	0.5967	0.0063	675.4952
Worker Vehicles	3.465	0.364	0.0253	0.3547	0.0032	332.0167
Total	**5.78**	**7.91**	**0.39**	**0.95**	**0.01**	**1,008**

Table C-17 (Concluded)
Construction of an LNG Plant – Structure Construction (Continued)

Total Incremental Combustion Emissions from Construction Activities

	CO	NOx	PM10	VOC	SOx	CO2
Sources	lb/day	lb/day	lb/day	lb/day	lb/day	lb/day
Daily Emissions	**26.0**	**60.0**	**3.01**	**7.21**	**0.05**	**5,091**
Annual Emissions	**2,466**	**5,699**	**286**	**685**	**5.1**	**483,652**

Combustion and Fugitive Summary	**PM2.5 Fraction[f]**	**PM10**	**PM2.5**
		lb/day	lb/day
Combustion, Offroad	0.92	2.6	2.4
Combustion, Onroad	0.964	0.4	0.38
Daily Emissions		**3.0**	**2.8**
Annual Emissions		**286.0**	**264.8**

Notes:

a) SCAQMD, staff estimation

b) Equipment name must match CARB Off-Road Model (see Off-Road Model EF worksheet) equipment name for sheet to look up EFs automatically.

c) SCAB values provided by the ARB, June 2007. Assumed equipment is diesel fueled.

d) CARB, EMFAC2002 as summarized on SCAQMD website at http://www.aqmd.gov/ceqa/handbook/onroad/onroadHHDT05_25.xls

e) Assumed haul truck travels 20 miles one-way

f) ARB's CEIDARS database PM2.5 fractions - construction dust category for offroad and onroad diesel vehicle exhaust category for combustion.

Table C-18
Construction of Control Equipment or Replacement of an ICE – Paving

		Construction Activity Concrete Paving
Construction Schedule -	**1**	**days**[a]

Equipment Type[a,b]	No. of Equipment	hr/day	Crew Size
Pavers	1	4.00	8
Paving Equipment	1	4.00	
Rollers	1	2.00	
Cement and Mortar Mixers	1	3.00	
Tractors/Loaders/Backhoes	1	4.00	

Construction Equipment Combustion Emission Factors

	CO	NOx	PM10	VOC	SOx	CO2
Equipment Type[c]	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr
Pavers	0.600	1.129	0.080	0.206	0.001	77.9
Paving Equipment	0.469	1.033	0.071	0.156	0.001	69.0
Rollers	0.442	0.907	0.063	0.141	0.001	67.1
Cement and Mortar Mixers	0.046	0.069	0.005	0.012	0.000	7.2
Tractors/Loaders/Backhoes	0.414	0.830	0.064	0.131	0.001	66.8

Construction Vehicle (Mobile Source) Emission Factors

	CO	NOx	PM10	VOC	SOx	CO2
	lb/mile	lb/mile	lb/mile	lb/mile	lb/mile	lb/mile
Heavy-Duty Truck[d]	0.01446237	0.04718166	0.00230900	0.00372949	0.00003962	4.221844935

Table C-18 (Continued)
Construction of Control Equipment or Replacement of an ICE – Paving

Construction Worker Number of Trips and Trip Length

Vehicle	No. of One-Way Trips/Day	Trip Length (miles)
Delivery Truck[e]	2	20
Water Truck[f]	3	4.5

Incremental Increase in Onsite Combustion Emissions from Construction Equipment

Equation: Emission Factor (lb/hr) x No. of Equipment x Work Day (hr/day) = Onsite Construction Emissions (lb/day)

Equipment Type	CO lb/day	NOx lb/day	PM10 lb/day	VOC lb/day	SOx lb/day	CO2 lb/day
Pavers	2.40	4.52	0.32	0.82	0.0036	311.74
Paving Equipment	1.88	4.13	0.28	0.62	0.0032	275.81
Rollers	0.88	1.81	0.13	0.28	0.0015	134.11
Cement and Mortar Mixers	0.14	0.21	0.01	0.04	0.0003	21.74
Tractors/Loaders/Backhoes	1.66	3.32	0.26	0.52	0.0031	267.23
Total	**7.0**	**14.0**	**1.0**	**2.3**	**0.012**	**1,010.63**

Incremental Increase in Onsite Combustion Emissions from Onroad Mobile Vehicles

Equation: Emission Factor (lb/mile) x No. of One-Way Trips/Day x 2 x Trip length (mile) = Mobile Emissions (lb/day)

Vehicle	CO lb/day	NOx lb/day	PM10 lb/day	VOC lb/day	SOx lb/day	CO2 lb/day
Delivery Truck	1.16	3.78	0.185	0.298	0.00317	337.7
Water Truck	0.39	1.27	0.062	0.10	0.001	114.0
Total	**1.55**	**5.05**	**0.25**	**0.40**	**0.0042**	**451.7**

Table C-18 (Concluded)
Construction of Control Equipment or Replacement of an ICE – Paving

Total Incremental Combustion Emissions from Construction Activities

Sources	CO lb/day	NOx lb/day	PM10 lb/day	VOC lb/day	SOx lb/day	CO2 lb/day
Daily Emissions	**8.5**	**19.0**	**1.2**	**2.7**	**0.0160**	**1,462**
Annual Emissions	**8.5**	**19.0**	**1.2**	**2.7**	**0.0160**	**1,462**

Combustion and Fugitive Summary	PM2.5 Fraction[g]	PM10 lb/day	PM2.5 lb/day
Combustion (Offroad)	0.92	1.0	0.9
Combustion (Onroad)	0.96	0.25	0.24
Fugitive	0.21	0	0.0
Daily Emissions		**1.2**	**1.2**
Annual Emissions		**1.2**	**1.2**

Notes:

a) SCAQMD, estimated from survey data, Sept 2004

b) Equipment name must match CARB Off-Road Model (see Off-Road Model EF worksheet) equipment name for sheet to look up EFs automatically.

c) SCAB values provided by the ARB, May 2007. Assumed equipment is diesel fueled.

d) CARB, EMFAC2007 (version 2.3) Burden Model, Winter 2007, 75 F, 40% RH: EF, lb/yr = (EF, ton/yr x 2,000 lb/ton)/VMT

e) Assumed haul truck travels 0.1 miles through facility

f) Assumed six foot wide water truck traverses over 140,000 square feet of disturbed area

g) ARB's CEIDARS database PM2.5 fractions - construction dust category for fugitive and diesel vehicle exhaust category for combustion.

Table C-19
Construction of Control Equipment or Replacement of an ICE – Equipment

Construction Activity
Internal Combustion Engine and Equipment Installation

Construction Schedule	2 days		
Equipment Type[a,b]	**No. of Equipment**	**hr/day**	**Crew Size**
Cranes	1	7.0	11
Rubber Tired Loaders	2	7.0	
Forklifts	3	7.0	
Welder	1	7.0	
Generator Sets	1	7.0	

Construction Equipment Combustion Emission Factors

	CO	**NOx**	**PM10**	**VOC**	**SOx**	**CO2**
Equipment Type[c]	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr
Cranes	0.637	1.695	0.075	0.188	0.001	128.7
Rubber Tired Loaders	0.555	1.382	0.077	0.173	0.001	108.6
Forklifts	0.250	0.643	0.035	0.086	0.001	54.4

Construction Vehicle (Mobile Source) Emission Factors

	CO	**NOx**	**PM10**	**VOC**	**SOx**	**CO2**
	lb/mile	lb/mile	lb/mile	lb/mile	lb/mile	lb/mile
Heavy-Duty Truck[d]	0.01446237	0.04718166	0.00230900	0.00372949	0.00003962	4.221844935
Passenger Vehicle	0.01155158	0.00121328	0.00008447	0.00118234	0.00001078	1.106722361

Table C-19 (Continued)
Construction of Control Equipment or Replacement of an ICE – Equipment

Number of Trips and Trip Length

Vehicle	No. of One-Way Trips/Day	One Way Trip Length (miles)
Haul Trucks[e]	4	20
Worker Vehicles	11	10

Incremental Increase in Onsite Idling Emissions from Onroad Mobile Vehicles

Equation: Emission Factor (lb/hr) x No. of Equipment x Work Day (hr/day) = Onsite Construction Emissions (lb/day)

Equipment Type	CO lb/day	NOx lb/day	PM10 lb/day	VOC lb/day	SOx lb/day	CO2 lb/day
Cranes	4.46	11.86	0.53	1.32	0.010	901
Rubber Tired Loaders	7.77	19.35	1.08	2.42	0.017	1,521
Forklifts	5.24	13.50	0.73	1.81	0.013	1,142
Welder	0.00	0.00	0.00	0.00	0.000	0
Generator Sets	0.00	0.00	0.00	0.00	0.000	0
Total	**17.47**	**44.72**	**2.33**	**5.55**	**0.039**	**3,564**

Incremental Increase in Onsite Combustion Emissions from Onroad Mobile Vehicles

Equation: Emission Factor (lb/mile) x No. of One-Way Trips/Day x 2 x Trip length (mile) = Mobile Emissions (lb/day)

Vehicle	CO lb/day	NOx lb/day	PM10 lb/day	VOC lb/day	SOx lb/day	CO2 lb/day
Flatbed Trucks	2.314	7.549	0.3694	0.5967	0.0063	675
Worker Vehicles	2.541	0.267	0.0186	0.2601	0.0024	243
Total	**4.86**	**7.82**	**0.39**	**0.86**	**0.01**	**919**

Table C-19 (Concluded)
Construction of Control Equipment or Replacement of an ICE – Equipment

Total Incremental Combustion Emissions from Construction Activities						
	CO	**NOx**	**PM10**	**VOC**	**SOx**	**CO2**
Sources	lb/day	lb/day	lb/day	lb/day	lb/day	lb/day
Daily Emissions	**22.3**	**52.5**	**2.7**	**6.4**	**0.048**	**4,483**
Annual Emissions	**44.6**	**105**	**5.4**	**13**	**0.096**	**8,965**

Combustion and Fugitive Summary	**PM2.5 Fraction[f]**	**PM10**	**PM2.5**
		lb/day	lb/day
Combustion, Offroad	0.92	2.3	2.1
Combustion, Onroad	0.964	0.4	0.37
Total, lb/project		**2.7**	**2.5**
		5.4	**5.0**

Notes:

a) SCAQMD, staff estimation

b) Equipment name must match CARB Off-Road Model (see Off-Road Model EF worksheet) equipment name for sheet to look up EFs automatically.

c) SCAB values provided by the ARB, May 2007. Assumed equipment is diesel fueled.

d) CARB, EMFAC2002 as summarized on SCAQMD website at http://www.aqmd.gov/ceqa/handbook/onroad/onroadHHDT05_25.xls

e) Assumed haul truck travels 20 miles one-way

f) ARB's CEIDARS database PM2.5 fractions - construction dust category for offroad and onroad diesel vehicle exhaust category for combustion.

Table C-20
Construction of Infrastructure or CEMS

Construction Activity
Internal Combustion Engine and Equipment Installation

Construction Schedule 2 days

Equipment Type[a,b]	**No. of Equipment**	**hr/day**	**Crew Size**
Cranes	1	4.0	8
Rubber Tired Loaders	1	4.0	
Forklifts	1	4.0	
Welder	1	7.0	
Generator Sets	1	7.0	

Construction Equipment Combustion Emission Factors

	CO	**NOx**	**PM10**	**VOC**	**SOx**	**CO2**
Equipment Type[c]	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr
Cranes	0.637	1.695	0.075	0.188	0.001	128.7
Rubber Tired Loaders	0.555	1.382	0.077	0.173	0.001	108.6
Forklifts	0.250	0.643	0.035	0.086	0.001	54.4
Welders	0.234	0.319	0.030	0.092	0.000	25.6
Generator Sets	0.355	0.725	0.045	0.113	0.001	61.0

Construction Vehicle (Mobile Source) Emission Factors

	CO	**NOx**	**PM10**	**VOC**	**SOx**	**CO2**
	lb/mile	lb/mile	lb/mile			lb/mile
Heavy-Duty Truck[d]	0.01446237	0.04718166	0.00230900	0.00372949	0.00003962	4.221844935
Passenger Vehicle	0.01155158	0.00121328	0.00008447	0.00118234	0.00001078	1.106722361

Table C-20 (Continued)
Construction of Infrastructure or CEMS

Number of Trips and Trip Length		
Vehicle	**No. of One-Way Trips/Day**	**One Way Trip Length (miles)**
Haul Trucks[e]	4	20
Worker Vehicles	8	10

Incremental Increase in Onsite Idling Emissions from Onroad Mobile Vehicles

Equation: Emission Factor (lb/hr) x No. of Equipment x Work Day (hr/day) = Onsite Construction Emissions (lb/day)

Equipment Type	**CO** lb/day	**NOx** lb/day	**PM10** lb/day	**VOC** lb/day	**SOx** lb/day	**CO2** lb/day
Cranes	2.55	6.78	0.30	0.75	0.0	515
Rubber Tired Loaders	2.22	5.53	0.31	0.69	0.0	434
Forklifts	1.00	2.57	0.14	0.34	0.0	218
Welder	1.64	2.23	0.21	0.64	0.0	179
Generator Sets	2.48	5.07	0.31	0.79	0.0	427
Total	**9.88**	**22.19**	**1.27**	**3.22**	**0.0**	**1,773**

Incremental Increase in Onsite Combustion Emissions from Onroad Mobile Vehicles

Equation: Emission Factor (lb/mile) x No. of One-Way Trips/Day x 2 x Trip length (mile) = Mobile Emissions (lb/day)

Vehicle	**CO** lb/day	**NOx** lb/day	**PM10** lb/day	**VOC** lb/day	**SOx** lb/day	**CO** lb/day
Flatbed Trucks	2.314	7.549	0.3694	0.5967	0.0063	675
Worker Vehicles	1.848	0.194	0.0135	0.1892	0.0017	177
Total	**4.16**	**7.74**	**0.38**	**0.79**	**0.01**	**853**

Table C-20 (Concluded)
Construction of Infrastructure or CEMS

Total Incremental Combustion Emissions from Construction Activities

Sources	**CO** lb/day	**NOx** lb/day	**PM10** lb/day	**VOC** lb/day	**SOx** lb/day	**CO2** lb/day
Daily Emissions	14.0	29.9	1.7	4.0	0.028	2,625
Annual Emissions	28.1	59.9	3.3	8.0	0.056	5,251

Combustion and Fugitive Summary	**PM2.5 Fraction**[f]	**PM10** lb/day	**PM2.5** lb/day
Combustion, Offroad	0.92	1.3	1.2
Combustion, Onroad	0.964	0.4	0.37
Daily Emissions		**1.7**	**1.5**
Annual Emissions		**3.3**	**3.1**

Notes:

a) SCAQMD, staff estimation

b) Equipment name must match CARB Off-Road Model (see Off-Road Model EF worksheet) equipment name for sheet to look up EFs automatically.

c) SCAB values provided by the ARB, May 2007. Assumed equipment is diesel fueled.

d) CARB, EMFAC2002 as summarized on SCAQMD website at http://www.aqmd.gov/ceqa/handbook/onroad/onroadHHDT05_25.xls

e) Assumed haul truck travels 20 miles one-way

f) ARB's CEIDARS database PM2.5 fractions - contruction dust category for offroad and onroad diesel vehicle exhaust category for combustion.

Table C-21
Construction Miscellaneous

Construction Activity
Internal Combustion Engine and Equipment Installation

Construction Schedule	1 day		
Equipment Type[a,b]	**No. of Equipment**	**hr/day**	**Crew Size**
Forklifts	1	4.0	4

Construction Equipment Combustion Emission Factors

	CO	**NOx**	**PM10**	**VOC**	**SOx**	**CO2**
Equipment Type[c]	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr
Forklifts	0.250	0.643	0.035	0.086	0.001	54.4

Construction Vehicle (Mobile Source) Emission Factors

	CO	**NOx**	**PM10**	**VOC**	**SOx**	**CO2**
	lb/mile	lb/mile	lb/mile	lb/mile	lb/mile	lb/mile
Heavy-Duty Truck[d]	0.01446237	0.04718166	0.00230900	0.00372949	0.00003962	4.221844935
Passenger Vehicle	0.01155158	0.00121328	0.00008447	0.00118234	0.00001078	1.106722361

On-Site Number of Trips and Trip Length

Vehicle	**No. of One-Way Trips/Day**	**One Way Trip Length (miles)**
Haul Trucks[e]	2	20
Worker Vehicles	4	10

Table C-21 (Continued)
Construction Miscellaneous

Incremental Increase in Onsite Idling Emissions from Onroad Mobile Vehicles

Equation: Emission Factor (lb/hr) x No. of Equipment x Work Day (hr/day) = Onsite Construction Emissions (lb/day)

	CO	NOx	PM10	VOC	SOx	CO2
Equipment Type	lb/day	lb/day	lb/day	lb/day	lb/day	lb/day
Forklifts	1.00	2.57	0.14	0.34	0.002	218
Total	**1.00**	**2.57**	**0.14**	**0.34**	**0.002**	**218**

Incremental Increase in Onsite Combustion Emissions from Onroad Mobile Vehicles

Equation: Emission Factor (lb/mile) x No. of One-Way Trips/Day x 2 x Trip length (mile) = Mobile Emissions (lb/day)

	CO	NOx	PM10	VOC	SOx	CO2
Vehicle	lb/day	lb/day	lb/day	lb/day	lb/day	lb/day
Flatbed Trucks	1.157	3.775	0.1847	0.2984	0.0032	338
Worker Vehicles	0.924	0.097	0.0068	0.0946	0.0009	89
Total	**2.08**	**3.87**	**0.19**	**0.39**	**0.00**	**426**

Total Incremental Combustion Emissions from Construction Activities

	CO	NOx	PM10	VOC	SOx	CO2
Sources	lb/day	lb/day	lb/day	lb/day	lb/day	lb/day
Daily Emissions	**3.1**	**6.4**	**0.3**	**0.7**	**0.007**	**644**
Annual Emissions	**3.1**	**6.4**	**0.33**	**0.74**	**0.007**	**644**

Combustion and Fugitive Summary	**PM2.5 Fraction**[f]	**PM10**	**PM2.5**
		lb/day	lb/day
Combustion, Offroad	0.92	0.1	0.1
Combustion, Onroad	0.964	0.2	0.18
Daily Emissions		**0.33**	**0.31**
Annual Emissions		**0.33**	**0.31**

Table C-21 (Concluded)
Construction Miscellaneous

Notes:

a) SCAQMD, staff estimation

b) Equipment name must match CARB Off-Road Model (see Off-Road Model EF worksheet) equipment name for sheet to look up EFs automatically.

c) SCAB values provided by the ARB, May 2007. Assumed equipment is diesel fueled.

d) CARB, EMFAC2002 as summarized on SCAQMD website at http://www.aqmd.gov/ceqa/handbook/onroad/onroadHHDT05_25.xls

e) Assumed haul truck travels 20 miles one-way

f) ARB's CEIDARS database PM2.5 fractions - construction dust category for offroad and onroad diesel vehicle exhaust category for combustion.

Table C-22
Offroad Emission Factors 2007

Equipment	CO lb/hr	NOx lb/hr	PM lb/hr	ROG lb/hr	SOX lb/hr	CO2 lb/hr	Fuel Use, gal/hr
Aerial Lifts	0.2253	0.4026	0.0279	0.0781	0.0004	34.7	
Air Compressors	0.3872	0.8302	0.0579	0.1285	0.0007	63.6	
Bore/Drill Rigs	0.5388	1.4734	0.0648	0.1457	0.0017	165.0	
Cement and Mortar Mixers	0.0455	0.0693	0.0050	0.0120	0.0001	7.2	0.33
Concrete/Industrial Saws	0.4487	0.7639	0.0640	0.1561	0.0007	58.5	
Cranes	0.6365	1.6948	0.0755	0.1882	0.0014	128.7	9.82
Crawler Tractors	0.7090	1.6218	0.0988	0.2180	0.0013	114.0	
Crushing/Proc. Equipment	0.7817	1.6553	0.1048	0.2499	0.0015	132.3	
Dumpers/Tenders	0.0383	0.0709	0.0049	0.0137	0.0001	7.6	
Excavators	0.5977	1.4225	0.0776	0.1816	0.0013	119.6	
Forklifts	0.2495	0.6430	0.0346	0.0861	0.0006	54.4	2.48
Generator Sets	0.3549	0.7249	0.0446	0.1130	0.0007	61.0	2.79
Graders	0.6712	1.7198	0.0886	0.2055	0.0015	132.7	6.06
Off-Highway Tractors	0.9270	2.2742	0.1107	0.2692	0.0017	151.5	
Off-Highway Trucks	0.9133	2.9144	0.1056	0.2881	0.0027	260.1	
Other Construction Equipment	0.4749	1.2411	0.0539	0.1311	0.0013	122.8	
Other General Industrial Equipmen	0.6987	1.9012	0.0850	0.2111	0.0016	152.2	
Other Material Handling Equipment	0.6298	1.8362	0.0819	0.2038	0.0015	141.2	
Pavers	0.6000	1.1291	0.0799	0.2062	0.0009	77.9	3.59
Paving Equipment	0.4693	1.0333	0.0708	0.1556	0.0008	69.0	3.16
Plate Compactors	0.0263	0.0351	0.0025	0.0054	0.0001	4.3	
Pressure Washers	0.0705	0.1079	0.0081	0.0235	0.0001	9.4	
Pumps	0.3243	0.6224	0.0439	0.1090	0.0006	49.6	
Rollers	0.4419	0.9073	0.0629	0.1410	0.0008	67.1	3.07
Rough Terrain Forklifts	0.4928	0.9631	0.0800	0.1576	0.0008	70.3	
Rubber Tired Dozers	1.6950	3.4143	0.1474	0.3789	0.0025	239.1	
Rubber Tired Loaders	0.5552	1.3821	0.0768	0.1730	0.0012	108.6	5.06
Scrapers	1.5249	3.3991	0.1465	0.3677	0.0027	262.5	10.74
Signal Boards	0.0972	0.1806	0.0115	0.0254	0.0002	16.7	
Skid Steer Loaders	0.2735	0.3375	0.0326	0.0981	0.0004	30.3	
Surfacing Equipment	0.7654	1.8498	0.0712	0.1864	0.0017	166.0	
Sweepers/Scrubbers	0.5672	1.0277	0.0819	0.1963	0.0009	78.5	
Tractors/Loaders/Backhoes	0.4142	0.8303	0.0639	0.1307	0.0008	66.8	3.41
Trenchers	0.5171	0.8578	0.0714	0.1942	0.0007	58.7	
Welders	0.2336	0.3191	0.0297	0.0917	0.0003	25.6	

SCAB values provided by the ARB, May 2007. Assumed equipment is diesel fueled.

Table C-23
2008 Construction Emissions

SCR

Description	**Annual No of Facilities**	**Daily No of Facilities**	**CO, lb/day**	**NOx, lb/day**	**PM10, lb/day**	**VOC, lb/day**	**SOx, lb/day**	**PM2.5, lb/day**	**CO2, lb/year**
Infrastructure	240	3	42.1	89.8	5.0	12.0	0.083	4.6	1,260,225
Total	240	3	**42.1**	**89.8**	**5.0**	**12.0**	0.083	**4.6**	**1,260,225**

Table C-24
2009 Construction Emissions

Description	**Annual No of Facilities**	**Daily No of Facilities**	**CO, lb/day**	**NOx, lb/day**	**PM10, lb/day**	**VOC, lb/day**	**SOx, lb/day**	**PM2.5, lb/day**	**CO2, lb/year**
CEMS	4	1	14.0	29.9	1.7	4.0	0.028	1.5	21,004
AFRC and CO analyzer	16	1	3.1	6.4	0.3	0.7	0.007	0.31	10,302
Electric Motor	4	1	22.3	52.5	2.7	6.4	0.048	2.5	41710
Total	24	3	**39.5**	**88.9**	**4.7**	**11.1**	**0.082**	**4.4**	**73,016**

Table C-25
2010 Construction Emissions

Description	**Annual No of Facilities**	**Daily No of Facilities**	**CO, lb/day**	**NOx, lb/day**	**PM10, lb/day**	**VOC, lb/day**	**SOx, lb/day**	**PM2.5, lb/day**	**CO2, lb/year**
Ox Cat or Update	20	1	22.3	52.5	2.7	6.4	0.048	2.5	208,551
CEMS	10	1	14.0	29.9	1.7	4.0	0.028	1.5	52,509
AFRC and CO analyzer	15	1	3.1	6.4	0.3	0.7	0.007	0.3	9,658
Electric Motor	13	1	22.3	52.5	2.7	6.4	0.048	2.5	135,558
Total	58	4	**61.8**	**141**	**7.4**	**17.6**	**0.130**	**6.9**	**406,277**

Table C-26
2011 Construction Emissions

SCR

Description	Annual No of Facilities	Daily No of Facilities	CO, lb/day	NOx, lb/day	PM10, lb/day	VOC, lb/day	SOx, lb/day	PM2.5, lb/day	CO2, lb/year
SCR	14	1	22.3	52.5	2.7	6.4	0.048	2.5	145,986
Ox Cat or Update	32	1	22.3	52.5	2.7	6.4	0.048	2.5	333,682
CEMS	10	1	14.0	29.9	1.7	4.0	0.028	1.5	52,509
CO Analyzer	5	1	3.1	6.4	0.33	0.74	0.007	0.31	3,219
Electric Motor	88	2	44.6	105	5.4	13	0.096	5.0	917,624
Total	149	6	**106**	**247**	**12.9**	**30.4**	**0.23**	**11.9**	**1,453,020**

Gas Turbine or Microturbine

Description	Annual No of Facilities	Daily No of Facilities	CO, lb/day	NOx, lb/day	PM10, lb/day	VOC, lb/day	SOx, lb/day	PM2.5, lb/day	CO2, lb/year
Gas Turbine or Microturbine	14	1	22.3	52.5	2.7	6.4	0.05	2.5	145,986
Ox Cat or Update	32	1	22.3	52.5	2.7	6.4	0.05	2.5	333,682
CEMS	10	1	14.0	29.9	1.7	4.0	0.03	1.5	52,509
CO Analyzer	5	1	3.1	6.4	0.33	0.74	0.01	0.31	3,219
Electric Motor	88	2	45	105	5.4	12.8	0.10	5.0	917,624
Total	149	6	**106.4**	**246.5**	**12.9**	**30.4**	**0.23**	**11.9**	**1,453,020**

Gas Turbine or Microturbine and LNG Plant

Description	Annual No of Facilities	Daily No of Facilities	CO, lb/day	NOx, lb/day	PM10, lb/day	VOC, lb/day	SOx, lb/day	PM2.5, lb/day	CO2, lb/year
LNG Plant	6	7	184	436	35.6	54	0.38	24	3,352,270
Gas Turbine or Microturbine	8	1	22.3	52.5	2.7	6.4	0.048	2.5	83,420
Ox Cat or Update	32	1	22.3	52.5	2.7	6.4	0.048	2.5	333,682
CEMS	10	1	14.0	29.9	1.7	4.0	0.028	1.5	52,509
CO Analyzer	5	1	3.1	6.4	0.33	0.74	0.007	0.31	3,219
Electric Motor	88	2	44.6	105	5.4	12.8	0.10	5.0	917,624
Total	149	13	**291**	**682**	**48.4**	**84.1**	**0.60**	**35.6**	**4,742,725**

Table C-27
2012 Construction Emissions

SCR

Description	Annual No of Facilities	Daily No of Facilities	CO, lb/day	NOx, lb/day	PM10, lb/day	VOC, lb/day	SOx, lb/day	PM2.5, lb/day	CO2, lb/year
SCR	14	1	22.3	52.5	2.7	6.4	0.048	2.5	145,986
Total	14	1	**22.3**	**52.5**	**2.7**	**6.4**	**0.048**	**2.5**	**145,986**

Gas Turbine or Microturbine

Description	Annual No of Facilities	Daily No of Facilities	CO, lb/day	NOx, lb/day	PM10, lb/day	VOC, lb/day	SOx, lb/day	PM2.5, lb/day	CO2, lb/year
Gas Turbine or Microturbine	14	1	22.3	52.5	2.7	6.4	0.048	2.5	145,986
Total	14	1	**22.3**	**52.5**	**2.7**	**6.4**	**0.048**	**2.5**	**145,986**

Gas Turbine or Microturbine and LNG Plant

Description	Annual No of Facilities	Daily No of Facilities	CO, lb/day	NOx, lb/day	PM10, lb/day	VOC, lb/day	SOx, lb/day	PM2.5, lb/day	CO2, lb/year
LNG Plant	6	7	184	436	35.6	53.8	0.38	23.7	3,352,270
Gas Turbine or Microturbine	8	1	22.3	52.5	2.7	6.4	0.048	2.5	83,420
Total	14	8	**207**	**488**	**38.3**	**60.2**	**0.43**	**26.2**	**3,435,691**

Table C-28
2008 Construction Vehicle Travel

Description	Annual No of Facilities	Daily No of Facilities	Daily HHD Distance, mile/day	Daily Worker, mile/day	Total HHD Distance, mile/ project	Total Worker, mile/ project	Daily HHD Distance, mile/day	Daily Worker, mile/day	Total HHD Distance, mile/ project	Total Worker, mile/ project
Infrastructure	240	3	160	160	320	320	480	480	76,800	76,800
Total	240	3	160	160	320	320	480	480	76,800	76,800

Table C-29
2009 Construction Vehicle Travel

Description	Annual No of Facilities	Daily No of Facilities	Daily HHD Distance, mile/day	Daily Worker, mile/day	Total HHD Distance, mile/ project	Total Worker, mile/ project	Daily HHD Distance, mile/day	Daily Worker, mile/day	Total HHD Distance, mile/ project	Total Worker, mile/ project
CEMS	4	1	160	160	320	320	160	160	1,280	1,280
AFRC and CO analyzer	16	1	80	80	80	80	80	80	1,280	1,280
Electric Motor	4	1	160	220	400	27	160	220	1,600	108
Total	24	3	880	1060	1920	801	400	460	4,160	2,668

Table C-30
2010 Construction Vehicle Travel

Description	Annual No of Facilities	Daily No of Facilities	Daily HHD Distance, mile/day	Daily Worker, mile/day	Total HHD Distance, mile/ project	Total Worker, mile/ project	Daily HHD Distance, mile/day	Daily Worker, mile/day	Total HHD Distance, mile/ project	Total Worker, mile/ project
Ox Cat or Update	20	1	160	220	400	27	160	220	3200	4400
CEMS	10	1	160	160	320	320	160	160	1600	1600
AFRC and CO analyzer	15	1	80	80	80	80	80	80	1200	1200
Electric Motor	13	1	160	220	400	27	160	220	2080	2860
Total	58	4	880	1,060	1,920	801	560	680	8,080	10,060

Table C-31
2011 Construction Vehicle Travel

SCR

Description	**Annual No of Facilities**	**Daily No of Facilities**	**Daily HHD Distance, mile/day**	**Daily Worker, mile/day**	**Total HHD Distance, mile/ project**	**Total Worker, mile/ project**	**Daily HHD Distance, mile/day**	**Daily Worker, mile/day**	**Total HHD Distance, mile/ project**	**Total Worker, mile/ project**
SCR	14	1	160	220	400	27	160	220	5,600	378
Ox Cat or Update	32	1	160	220	400	27	160	220	12,800	864
CEMS	10	1	160	160	320	320	160	160	3,200	3,200
CO Analyzer	5	1	80	80	80	80	80	80	400	400
Electric Motor	88	2	160	220	400	27	320	440	35,200	2,376
Total	149	6	720	900	1600	481	880	1120	57,200	7,218

Gas Turbine or Microturbine

Description	**Annual No of Facilities**	**Daily No of Facilities**	**Daily HHD Distance, mile/day**	**Daily Worker, mile/day**	**Total HHD Distance, mile/ project**	**Total Worker, mile/ project**	**Daily HHD Distance, mile/day**	**Daily Worker, mile/day**	**Total HHD Distance, mile/ project**	**Total Worker, mile/ project**
Gas Turbine or Microturbine	15	1	160	220	400	27	160	220	6,000	405
Ox Cat or Update	15	1	160	220	400	27	160	220	6,000	405
CEMS	2	1	160	160	320	320	160	160	640	640
Electric Motor	118	2	160	220	400	27	320	440	47,200	3,186
Total	150	5	640	820	1,520	401	800	1,040	59,840	4,636

Table C-31 (Concluded)
2011 Construction Vehicle Travel

Gas Turbine or Microturbine and LNG Plant

Description	Annual No of Facilities	Daily No of Facilities	Daily HHD Distance, mile/day	Daily Worker, mile/day	Total HHD Distance, mile/ project	Total Worker, mile/ project	Daily HHD Distance, mile/day	Daily Worker, mile/day	Total HHD Distance, mile/ project	Total Worker, mile/ project
LNG Plant	6	7	547	300	18,800	270	3,830	2,100	112,800	1,620
Gas Turbine or Microturbine	8	1	160	220	400	27	160	220	3,200	216
Ox Cat or Update	32	1	160	220	400	27	160	220	12,800	864
CEMS	10	1	160	160	320	320	160	160	3,200	3,200
CO Analyzer	5	1	80	80	80	80	80	80	400	400
Electric Motor	88	2	160	220	400	27	320	440	35,200	2,376
Total	149	13	1267.2	1200	20400	751	4710.4	3220	167,600	8,676

Table C-32
2012 Construction Vehicle Travel

SCR

Description	Annual No of Facilities	Daily No of Facilities	Daily HHD Distance, mile/day	Daily Worker, mile/day	Total HHD Distance, mile/ project	Total Worker, mile/ project	Daily HHD Distance, mile/day	Daily Worker, mile/day	Total HHD Distance, mile/ project	Total Worker, mile/ project
SCR	14	1	160	220	400	27	160	220	5,600	378
Total	14	1	160	220	400	27	160	220	5600	378

Gas Turbine or Microturbine

Description	Annual No of Facilities	Daily No of Facilities	Daily HHD Distance, mile/day	Daily Worker, mile/day	Total HHD Distance, mile/ project	Total Worker, mile/ project	Daily HHD Distance, mile/day	Daily Worker, mile/day	Total HHD Distance, mile/ project	Total Worker, mile/ project
Gas Turbine or Microturbine	14	1	160	220	400	27	160	220	5,600	378
Total	14	1	160	220	400	27	160	220	5600	378

Table C-32 (Concluded)
2012 Construction Vehicle Travel

Gas Turbine or Microturbine and LNG Plant

Description	Annual No of Facilities	Daily No of Facilities	Daily HHD Distance, mile/day	Daily Worker, mile/day	Total HHD Distance, mile/ project	Total Worker, mile/ project	Daily HHD Distance, mile/day	Daily Worker, mile/day	Total HHD Distance, mile/ project	Total Worker, mile/ project
LNG Plant	6	7	547	300	18,800	270	3,830	2,100	112,800	1,620
Gas Turbine or Microturbine	8	1	160	220	15,280	27	160	220	122,240	216
Total	14	8	707.2	520	34080	297	3990.4	2320	235040	1836

Table C-33
EMFAC2007 Emission Factors for 2007

Description	NOx, lb/mile	CO, lb/mile	VOC, lb/mile	SOx, lb/mile	PM10, lb/mile	CO2, lb/mile
Heavy-Duty Truck[a]	0.04718	0.01446	0.00373	0.00004	0.00231	4.222

CARB, EMFAC2002 as summarized on SCAQMD website at http://www.aqmd.gov/ceqa/handbook/onroad/onroadHHDT05_25.xls

Table C-34
Summary of Construction Emissions

SCR-Construction

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5, lb/day	CO2, ton/year
2008	89.8	42.1	12.0	0.08	5.0	4.6	630
2009	88.9	39.5	11.1	0.08	4.7	4.4	36.5
2010	141.4	61.8	17.6	0.13	7.4	6.9	203
2011	247	106	30.4	0.23	12.9	11.9	727
2012	52.5	22.3	6.4	0.05	2.7	2.5	73.0

Table C-34 (Concluded)
Summary of Construction Emissions

Gas Turbines or Microturbines - Construction

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5, lb/day	CO2, ton/year
2008	89.8	42.1	12.0	0.08	5.0	4.6	630
2009	88.9	39.5	11.1	0.08	4.7	4.4	36.5
2010	141.4	61.8	17.6	0.13	7.4	6.9	203
2011	247	106	30.4	0.23	12.9	11.9	727
2012	52.5	22.3	6.4	0.05	2.7	2.5	73.0

Gas Turbines/LNG - Construction

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5, lb/day	CO2, ton/year
2008	89.8	42.1	12.0	0.08	5.0	4.6	630
2009	88.9	39.5	11.1	0.08	4.7	4.4	36.5
2010	141.4	61.8	17.6	0.13	7.4	6.9	203
2011	682	291	84.1	0.60	48.4	35.6	2,371
2012	488	206.6	60.2	0.43	38.3	26.2	1,718

Table C-35
Summary of Total Proposed Project Emissions

SCR - Total

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5 lb/day	~~CO2, ton/year~~
2008	~~9,089~~ 9,094	~~53,909~~ 53,942	~~2,470~~ 2,479	~~544~~ 545	~~877~~ 878	~~875~~ 876	~~1,227,861~~
2009	~~6,410~~ 6,415	~~22,399~~ 22,432	~~1,790~~ 1,799	~~543~~ 544	~~858~~ 859	~~856~~ 857	~~1,231,763~~
2010	~~5,964~~ 5,969	~~17,357~~ 17,390	~~1,298~~ 1,307	~~534~~ 535	~~844~~ 845	~~842~~ 843	~~1,208,074~~
2011	~~5,591~~ 5,596	~~13,581~~ 13,614	~~1,237~~ 1,246	~~529~~ 530	~~834~~ 835	~~831~~ 832	~~1,197,378~~
2012	4,178	13,445	1,017	538	833	831	~~1,231,668~~
2014	4,184	13,441	1,015	538	833	831	~~1,231,622~~

Gas Turbines - Total

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5 lb/day	~~CO2, ton/year~~
2008	~~9,089~~ 9,094	~~53,909~~ 53,942	~~2,470~~ 2,479	~~544~~ 545	~~877~~ 878	~~875~~ 876	~~1,227,861~~
2009	~~6,410~~ 6,415	~~22,399~~ 22,432	~~1,790~~ 1,799	~~543~~ 544	~~858~~ 859	~~856~~ 857	~~1,231,763~~
2010	~~5,964~~ 5,969	~~17,357~~ 17,390	~~1,298~~ 1,307	~~534~~ 535	~~844~~ 845	~~842~~ 843	~~1,208,074~~
2011	~~5,586~~ 5,591	~~13,579~~ 13,612	~~1,237~~ 1,246	~~529~~ 530	~~833~~ 834	~~831~~ 832	~~1,197,447~~
2012	4,878	7,380	539	538	1,019	1,017	~~1,231,344~~
2014	4,884	7,375	537	538	1,019	1,017	~~1,231,271~~

Table C-35 (Continued)
Summary of Total Proposed Project Emissions

Microturbines - Total

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5 lb/day	~~CO2, ton/year~~
2008	~~9,089~~ 9,094	~~53,909~~ 53,942	~~2,470~~ 2,479	~~544~~ 545	~~877~~ 878	~~875~~ 876	~~1,227,861~~
2009	~~6,410~~ 6,415	~~22,399~~ 22,432	~~1,790~~ 1,799	~~543~~ 544	~~858~~ 859	~~856~~ 857	~~1,231,763~~
2010	~~5,964~~ 5,969	~~17,357~~ 17,390	~~1,298~~ 1,307	~~534~~ 535	~~844~~ 845	~~842~~ 843	~~1,208,074~~
2011	~~5,586~~ 5,591	~~13,579~~ 13,612	~~1,237~~ 1,246	~~529~~ 530	~~833~~ 834	~~831~~ 832	~~1,197,447~~
2012	3,913	6,192	644	538	760	758	~~1,231,458~~
2014	3,919	6,187	643	538	760	758	~~1,231,385~~

Gas Turbines/LNG - Total

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5 lb/day	~~CO2, ton/year~~
2008	~~9,089~~ 9,094	~~53,909~~ 53,942	~~2,470~~ 2,479	~~544~~ 545	~~877~~ 878	~~875~~ 876	~~1,227,861~~
2009	~~6,410~~ 6,415	~~22,399~~ 22,432	~~1,790~~ 1,799	~~543~~ 544	~~858~~ 859	~~856~~ 857	~~1,231,763~~
2010	~~5,964~~ 5,969	~~17,357~~ 17,390	~~1,298~~ 1,307	~~534~~ 535	~~844~~ 845	~~842~~ 843	~~1,208,074~~
2011	~~6,072~~ 6,077	~~13,779~~ 13,812	~~1,295~~ 1,304	~~529~~ 530	~~872~~ 873	~~857~~ 858	~~1,199,341~~
2012	4,742	6,710	584	211	911	896	~~1,094,941~~
2014	4,373	6,540	533	211	878	876	~~1,093,551~~

Table C-35 (Concluded)
Summary of Total Proposed Project Emissions

Microturbines/LNG - Total

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5 lb/day	~~CO2, ton/year~~
2008	~~9,089~~ 9,094	~~53,909~~ 53,942	~~2,470~~ 2,479	~~544~~ 545	~~877~~ 878	~~875~~ 876	~~1,227,861~~
2009	~~6,410~~ 6,415	~~22,399~~ 22,432	~~1,790~~ 1,799	~~543~~ 544	~~858~~ 859	~~856~~ 857	~~1,231,763~~
2010	~~5,964~~ 5,969	~~17,357~~ 17,390	~~1,298~~ 1,307	~~534~~ 535	~~844~~ 845	~~842~~ 843	~~1,208,074~~
2011	~~6,072~~ 6,077	~~13,779~~ 13,812	~~1,295~~ 1,304	~~529~~ 530	~~872~~ 873	~~857~~ 858	~~1,199,341~~
2012	4,358	6,245	629	211	805	791	~~1,095,049~~
2014	3,989	6,075	578	211	773	771	~~1,093,659~~

Table C-36
Summary of Emissions and Emission Reductions from PAR 1110.2

SCR - Total Compared to Baseline

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5 lb/day	CO2, ton/year
2008	~~(106)~~ (100)	~~(334)~~ (301)	~~(23)~~ (14)	~~(7.4)~~ (6.8)	~~0.1~~ 1.0	~~0.4~~ 0.7	~~(22,186)~~
2009	~~(3,231)~~ (3,225)	~~(36,886)~~ (36,853)	~~(1,195)~~ (1,186)	~~(17)~~ (17)	~~(33)~~ (32)	~~(33)~~ (32)	~~(41,973)~~
2010	~~(3,231)~~ (3,225)	~~(36,886)~~ (36,853)	~~(1,195)~~ (1,186)	~~(17)~~ (17)	~~(33)~~ (32)	~~(33)~~ (32)	~~(41,973)~~
2011	~~(3,603)~~ (3,598)	~~(40,662)~~ (40,629)	~~(1,256)~~ (1,247)	~~(23)~~ (22)	~~(43)~~ (42)	~~(44)~~ (43)	~~(52,669)~~
2012	(5,017)	(40,798)	(1,476)	(13)	(44)	(44)	~~(18,379)~~
2014	(5,011)	(40,802)	(1,477)	(13)	(44)	(44)	~~(18,425)~~

Table C-36 (Continued)
Summary of Emissions and Emission Reductions from PAR 1110.2

Gas Turbines - Total Compared to Baseline

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5 lb/day	~~CO2, ton/year~~
2008	~~(106)~~	~~(334)~~	~~(23)~~	~~(7.5)~~	~~0.1~~	~~0.4~~	~~(22,186)~~
	(100)	(301)	(14)	(6.8)	1.0	0.7	
2009	~~(3,231)~~	~~(36,886)~~	~~(1,194)~~	~~(18)~~	~~(33)~~	~~(33)~~	~~(41,973)~~
	(3,225)	(36,853)	(1,186)	(17)	(32)	(32)	
2010	~~(3,231)~~	~~(36,886)~~	~~(1,195)~~	~~(18)~~	~~(33)~~	~~(33)~~	~~(41,973)~~
	(3,225)	(36,853)	(1,186)	(17)	(32)	(32)	
2011	~~(3,609)~~	~~(40,664)~~	~~(1,256)~~	~~(23)~~	~~(43)~~	~~(44)~~	~~(52,600)~~
	(3,603)	(40,631)	(1,247)	(22)	(43)	(43)	
2012	(4,317)	(46,863)	(1,954)	(13)	142	142	~~(18,703)~~
2014	(4,311)	(46,868)	(1,955)	(13)	142	142	~~(18,776)~~

Microturbines - Total Compared to Baseline

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5 lb/day	~~CO2, ton/year~~
2008	~~(106)~~	~~(334)~~	~~(22)~~	~~(7.5)~~	~~(0.1)~~	~~0.4~~	~~(22,186)~~
	(100)	(301)	(14)	(6.9)	0.8	0.4	
2009	~~(3,231)~~	~~(36,886)~~	~~(1,194)~~	~~(18)~~	~~(33)~~	~~(33)~~	~~(41,973)~~
	(3,225)	(36,853)	(1,186)	(17)	(32)	(32)	
2010	~~(3,231)~~	~~(36,886)~~	~~(1,194)~~	~~(18)~~	~~(33)~~	~~(33)~~	~~(41,973)~~
	(3,225)	(36,853)	(1,186)	(17)	(32)	(32)	
2011	~~(3,609)~~	~~(40,664)~~	~~(1,256)~~	~~(23)~~	~~(43)~~	~~(44)~~	~~(52,600)~~
	(3,603)	(40,631)	(1,247)	(22)	(43)	(43)	
2012	(5,282)	(48,051)	(1,848)	(13)	(117)	(117)	~~(18,589)~~
2014	(5,275)	(48,056)	(1,850)	(13)	(117)	(117)	~~(18,662)~~

Table C-36 (Concluded)
Summary of Emissions and Emission Reductions from PAR 1110.2

Gas Turbines/LNG - Total Compared to Baseline

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5 lb/day	~~CO_2, ton/year~~
2008	~~(106)~~	~~(334)~~	~~(22)~~	~~(7.5)~~	~~(0.1)~~	~~0.4~~	~~(22,186)~~
	(100)	(301)	(14)	(6.9)	0.8	0.4	
2009	~~(3,231)~~	~~(36,886)~~	~~(1,194)~~	~~(18)~~	~~(33)~~	~~(33)~~	~~(41,973)~~
	(3,225)	(36,853)	(1,186)	(17)	(32)	(32)	
2010	~~(3,231)~~	~~(36,886)~~	~~(1,195)~~	~~(17)~~	~~(33)~~	~~(33)~~	~~(41,973)~~
	(3,225)	(36,853)	(1,186)	(17)	(32)	(32)	
2011	~~(3,123)~~	~~(40,464)~~	~~(1,198)~~	~~(22)~~	~~(5)~~	~~(18)~~	~~(50,706)~~
	(3,117)	(40,431)	(1,189)	(22)	(4)	(17)	
2012	(4,453)	(47,533)	(1,909)	(340)	33.7	21.3	~~(155,106)~~
2014	(4,821)	(47,703)	(1,960)	(340)	1.2	0.75	~~(156,496)~~

Microturbines/LNG - Total Compared to Baseline

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5 lb/day	~~CO_2, ton/year~~
2008	~~(106)~~	~~(334)~~	~~(22)~~	~~(7.5)~~	~~(0.1)~~	~~0.4~~	~~(22,186)~~
	(100)	(301)	(14)	(6.9)	0.8	0.4	
2009	~~(3,231)~~	~~(36,886)~~	~~(1,194)~~	~~(18)~~	~~(33)~~	~~(33)~~	~~(41,973)~~
	(3,225)	(36,853)	(1,186)	(17)	(32)	(32)	
2010	~~(3,231)~~	~~(36,886)~~	~~(1,195)~~	~~(17)~~	~~(33)~~	~~(33)~~	~~(41,973)~~
	(3,225)	(36,853)	(1,186)	(17)	(32)	(32)	
2011	~~(3,123)~~	~~(40,464)~~	~~(1,198)~~	~~(22)~~	~~(5)~~	~~(18)~~	~~(50,706)~~
	(3,117)	(40,431)	(1,189)	(22)	(4)	(17)	
2012	(4,837)	(47,998)	(1,864)	(340)	(72)	(84)	~~(154,998)~~
2014	(5,205)	(48,168)	(1,914)	(340)	(104)	(104)	~~(156,387)~~

Table C-37
Estimation of the Number of Electric Motor Replacements of Non-Biogas Engines Required for PAR 1110.2 to Be Carbon Neutral

SCR - Carbon Neutral Calculation

Description	Proposed Project CO2, ton/year	No Electrification CO2, ton/year	Reduction in CO2 from Electrification	Average CO2 Savings per Motor	Average No of Motor to Stay Carbon Neutral
Baseline					
2008	(22,186)	(22,186)	0		
2009	(41,973)	(23,358)	18,614		
2010	(41,973)	(23,358)	18,614		
2011	(52,669)	(21,974)	30,695		
2012	(18,379)	11,559	29,938		
2014	(18,425)	11,513	29,938		
2013-2018	(110,549)	69,081	179,630		
10 year total	(265,542)	11,950	277,492	1,642	8

Gas Turbines - Carbon Neutral Calculation

Description	Proposed Project CO2, ton/year	No Electrification CO2, ton/year	Reduction in CO2 from Electrification	Avg CO2 Savings per Motor	Avg No of Motor to Stay Carbon Neutral
Baseline					
2008	(22,186)	(22,181)	5		
2009	121,080	(23,358)	18,614		
2010	(41,973)	(23,358)	18,614		
2011	(52,600)	(21,905)	30,695		
2012	(18,703)	11,236	29,938		
2014	(18,776)	11,163	29,938		
2013-2018	(112,654)	66,976	179,630		
10 year total	(104,849)	9,591	114,439	677	15

Table C-37 (Continued)
Estimation of the Number of Electric Motor Replacements of Non-Biogas Engines Required for PAR 1110.2 to Be Carbon Neutral

Microturbines - Carbon Neutral Calculation

Description	Proposed Project CO2, ton/year	No Electrification CO2, ton/year	Reduction in CO2 from Electrification	Average CO2 Savings per Motor	Average No of Motor to Stay Carbon Neutral
Baseline					
2008	(22,186)	(22,181)	5		
2009	(41,973)	(23,358)	18,614		
2010	(41,973)	(23,358)	18,614		
2011	(52,600)	(21,905)	30,695		
2012	(18,589)	11,350	29,938		
2014	(18,662)	11,277	29,938		
2013-2018	(111,970)	67,660	179,630		
10 year total	(267,103)	10,389	277,492	1,642	7

Gas Turbines/LNG - Carbon Neutral Calculation

Description	Proposed Project CO2, ton/year	No Electrification CO2, ton/year	Reduction in CO2 from Electrification	Avg CO2 Savings per Motor	Avg No of Motor to Stay Carbon Neutral
Baseline					
2008	(22,186)	(22,181)	5		
2009	(41,973)	(23,358)	18,614		
2010	(41,973)	(23,358)	18,614		
2011	(50,706)	(20,011)	30,695		
2012	(155,106)	(125,168)	29,938		
2014	(156,496)	(126,558)	29,938		
2013-2018	(938,975)	(759,345)	179,630		
10 year total	(1,228,732)	(951,240)	277,492	1,642	0

Table C-37 (Concluded)
Estimation of the Number of Electric Motor Replacements of Non-Biogas Engines Required for PAR 1110.2 to Be Carbon Neutral

Microturbines/LNG - Carbon Neutral Calculation

Description	Proposed Project CO2, ton/year	No Electrification CO2, ton/year	Reduction in CO2 from Electrification	Avg CO2 Savings per Motor	Avg No of Motor to Stay Carbon Neutral
Baseline					
2008	(22,186)	(22,181)	5		
2009	(41,973)	(23,358)	18,614		
2010	(41,973)	(23,358)	18,614		
2011	(50,706)	(20,011)	30,695		
2012	(154,998)	(125,059)	29,938		
2014	(156,387)	(126,449)	29,938		
2013-2018	(938,325)	(758,695)	179,630		
10 year total	(1,227,973)	(950,481)	277,492	1,642	0

Project CO2 emissions begin with the adoption of the rule.
Electric engines would be installed between 2009 and 2011. Electric motor useful life was assumed to be 10 years. The electric motor useful life was assumed to start in 2009. CO2 emissions were not estimated for 2013. The emissions for 2013 are assumed to be equivalent to 2014. This is conservative because in 2013 the catalyst disposal and replacement would not start until 2014, which adds diesel haul truck emissions.

Table C-38
Summary of the Number of Electric Motor Replacements of Non-Biogas Engines Required for PAR 1110.2 to Be Carbon Neutral

Description	Proposed Project CO2, ton/year	No Electrification CO2, ton/year	Reduction in CO2 from Electrification	Average CO2 Savings per Motor	Average No of Motor to Stay Carbon Neutral
SCR	(270,810)	11,981	282,791	1,673	8
Replace ICE with Gas Turbine	(104,849)	9,591	114,439	677	15
Replace ICE Microturbine	(267,103)	10,389	277,492	1,642	7
Replace LFG w LNG, DG w Turbines	(1,228,732)	(951,240)	277,492	1,642	0
Replace LFG w LNG, DG w Microturbines	(1,227,973)	(950,481)	277,492	1,642	0

SCAQMD staff estimates that there are 225 non-biogas engines where replacing the non-biogas engines with electric motors would cost less than complying with PAR 1110.2.
The proposed project assumes that 75 percent of existing non-biogas ICEs (169) would be replaced with electrification where cost would be lower than complying with PAR 1110.2.

Table C-39
Adverse Electricity Impacts from Differences in Efficiency Between ICE Alternatives and LNG Reliance on the Power Grid

Description	Electricity Production, MWH/yr	Electricity Consumption, MWH/yr	Total Electricity, MWH/yr	Electricity Change from Baseline, MWH/yr
2005 Baseline (ICE)	437,214		437,214	
SCR	435,509		435,509	1,706
Gas Turbines	380,053		380,053	57,161
Microturbines	336,201		336,201	101,013
Gas Turbines/LNG	155,746	104,694	51,052	386,162
Microturbines/LNG	137,706	104,694	33,081	404,133

ICEs, gas turbines, and microturbines generate electricity.
LNG plants would not generate electricity, but would require energy from the power grid.

Table C-40
Adverse Electricity Impacts

Description	Non-Biogas and Biogas CEMS and Controllers, MWH/Yr	Non-Biogas Electrification, MWH/Yr	Electricity Production, MWH/yr	Electricity Totals, MWH/yr	Electricity Change from Baseline, MWH/yr
2005 Baseline			437,214	437,214	0
SCR	(567)	(171,827)	435,509	263,114	(174,100)
Gas Turbines	(567)	(171,827)	380,053	207,659	(229,556)
Micro Turbines	(567)	(171,827)	336,201	163,807	(273,408)
Gas Turbines/LNG	(567)	(171,827)	51,052	(121,342)	(558,557)
Microturbines/LNG	(567)	(171,827)	33,081	(139,313)	(576,527)

Negative values are presented in parenthesis. Negative electricity values represent consumption, positive values represent production.

Table C-41
Adverse Natural Gas Impacts from Reduction of Natural Gas Usage to 10 Percent

Year	Baseline Natural Gas Usage, MMBtu/ year	2008 Natural Gas Reduction, MMBtu/ year	2010 Natural Gas Reduction, MMBtu/ year
2008	4,061,047	162,928	77,761
2010	4,964,605	199,179	95,063

Table C-42
Diesel Fuel Use from Truck Trips Associated with PAR 1110.2

Natural Gas Reduction from ICE Replacement with Electric Motors, MMBtu/year	Power Plants, MMBtu/year	Emergency ICE, MMBtu/year	Electrification Natural Gas Consumption, MMBtu/year
(1,854,358)	1,303,214	2,283	(548,862)

Values in parenthesis are negative. Reduction in natural gas use is negative, consumption is positive

Table C-43
Adverse Natural Gas Impacts

Description	Catalyst Pressure Drop Consumption, MMBtu/yr	Non-biogas Electrification Natural Gas Consumption, MMBtu/yr	Biogas Emergency Engines Natural Gas, MMBtu/yr	Power Plant Natural Gas, MMBtu/Yr	Biogas Natural Gas Consumption, MMBtu/yr	Non-biogas Natural Gas Consumption, MMBtu/yr	Natural Gas Total, MMBtu/yr	Natural Gas Change from Baseline, MMBtu/yr
Baseline					512,787	10,501,630	11,014,417	
SCR	2,713	(548,862)		1,751	512,787	10,501,630	10,470,019	(544,398)
Gas Turbines	2,713	(548,862)	3,318	68,793	512,787	10,501,630	10,540,378	(474,039)
Micro Turbines	2,713	(548,862)	5,023	112,645	512,787	10,501,630	10,585,936	(428,481)
Gas Turbines/LNG	2,713	(548,862)	3,318	397,794	456,430	10,501,630	10,813,022	(201,395)
Microturbines/LNG	2,713	(548,862)	5,023	415,764	456,430	10,501,630	10,832,698	(181,719)

Values in parenthesis are negative. Reduction in natural gas use is negative, consumption is positive

Table C-44
Diesel Fuel Use from Truck Trips Associated with Non-biogas and the SCR Biogas Compliance Option

Year	Daily HHD Consumption Construction, gal/day	Diesel Construction Equipment, gal/day	Daily HHD Consumption Operational gal/day	Non-Biogas Emergency Engines, gal/day	Daily Consumption, gal/day
2008	24	267	9	0	300
2009	20	279	6	65	370
2010	28	373	54	760	1,214
2011	44	653	63	1,111	1,871
2012	8	141	86	1,111	1,346
2014	0	0	149	1,111	1,260
Max	44	653	149	1,111	1,957

HHDT = Heavy – heavy- duty truck

Table C-45
Diesel Fuel Use from Truck Trips Associated with Non-biogas and the Gas Turbine Biogas Compliance Option

Year	Daily HHD Consumption Construction, gal/day	Diesel Construction Equipment, gal/day	Daily HHD Consumption Operational gal/day	Non-Biogas Emergency Engines, gal/day	Non-Biogas Emergency Engines, gal/day	Daily Consumption, gal/day
2008	24	267	9	0	0	300
2009	20	367	6	65	0	458
2010	28	373	54	760	0	1,214
2011	44	653	57	1,111	0	1,865
2012	8	141	86	1,111	0	1,346
2014	0	0	149	1,111	140	1,399
Max	44	653	149	1,111	140	1,865

HHDT = Heavy – heavy- duty truck

Table C-46
Diesel Fuel Use from Truck Trips Associated with Non-biogas and the Microturbine Biogas Compliance Option

Year	Daily HHD Consumption Construction, gal/day	Diesel Construction Equipment, gal/day	Daily HHD Consumption Operational gal/day	Non-Biogas Emergency Engines, gal/day	Non-Biogas Emergency Engines, gal/day	Daily Consumption, gal/day
2008	24.0	267	9.0	0	0	300
2009	20.0	367	6.0	65	0	458
2010	28.0	373	53.6	760	0	1,214
2011	44.0	653	56.6	1,111	0	1,865
2012	8.0	141	86.4	1,111	0	1,346
2014	0.0	0	149	1,111	202	148.8
Max	44	653	149	1,111	202	1,865

HHDT = Heavy – heavy- duty truck

Table C-47
Diesel Fuel Use from Truck Trips Associated with Non-biogas and the LNG and Gas Turbine Biogas Compliance Option

Year	Daily HHD Consumption Construction, gal/day	Diesel Construction Equipment, gal/day	Daily HHD Consumption Operational gal/day	Non-Biogas Emergency Engines, gal/day	Non-Biogas Emergency Engines, gal/day	Daily Consumption, gal/day
2008	24	267	9	0	0	300
2009	20	279	6	65	0	370
2010	28	373	54	760	0	1,214
2011	236	1,761	111	1,111	0	3,218
2012	200	1,249	154	1,111	0	2,714
2014	0	0	281	1,111	140	1,531
Max	236	1,761	281	1,111	140	3,218

HHDT = Heavy – heavy- duty truck

Table C-48
Diesel Fuel Use from Truck Trips Associated with Non-biogas and the LNG and Microturbine Biogas Compliance Option

Year	Daily HHD Consumption Construction, gal/day	Diesel Construction Equipment, gal/day	Daily HHD Consumption Operational gal/day	Non-Biogas Emergency Engines, gal/day	Non-Biogas Emergency Engines, gal/day	Daily Consumption, gal/day
2008	24.0	267	9.0	0	0	300
2009	20.0	279	6.0	65	0	370
2010	28.0	373	53.6	760	0	1,214
2011	236	1,761	111	1,111	0	3,218
2012	200	1,249	154	1,111	0	2,714
2014	0.0	0	281	1,111	202	1,593
Max	236	1,761	281	1,111	202	3,218

HHDT = Heavy – heavy- duty truck

Table C-49
Summary of Energy Effects Non-Biogas Effects

Natural Gas Consumption, MMBtu/Yr	Electricity Consumption, MWH/Yr	Diesel Fuel Consumption, Gal/Yr
(551,144,402,851)	172,394	55,536

Table C-50
Summary PAR 1110.2 Energy Effects Compared to Baseline

Description	Natural Gas Consumption, MMBtu/yr	Electricity Production, MWH/yr	Shaft Work Produced, Hp-Hrs/yr	Diesel Fuel Consumption, gal/yr	LNG Production, MMBtu/yr
SCR	(544,398)	174,100	(59,006)	31,152	
Gas Turbines	(474,039)	229,556	(15,123,937)	38,128	
Micro Turbines	(428,481)	273,408	(15,123,937)	41,241	
Gas Turbines/LNG	(201,395)	558,557	(15,123,937)	38,128	2,374,019
Microturbines/LNG	(181,719)	576,527	(15,123,937)	57,364	2,374,019

Table C-51
Example ISCST3 File for Ammonia Slip Emissions

```
**
****************************************
**
** ISCST3 Input Produced by:
** ISC-AERMOD View Ver. 5.6.0
** Lakes Environmental Software Inc.
** Date: 8/14/2007
**
****************************************
**
**
****************************************
** ISCST3 Control Pathway
****************************************
**
**
CO STARTING
   TITLEONE
   TITLETWO
   MODELOPT CONC  URBAN NOCALM
   AVERTIME 1 PERIOD
   POLLUTID OTHER
   TERRHGTS ELEV
   RUNORNOT RUN
CO FINISHED
**
****************************************
** ISCST3 Source Pathway
****************************************
**
**
SO STARTING
   ELEVUNIT FEET
** Source Location **
** Source ID - Type - X Coord. - Y Coord. **
   LOCATION S008 POINT 412935.000 3728400.900 23.000
   LOCATION S009 POINT 412942.100 3728391.300 23.000
** Source Parameters **
   SRCPARAM S008 1 18.902 533.150 17.88100 0.762
   SRCPARAM S009 1 18.902 533.150 17.88100 0.762
```

Table C-51 (Continued)
Example ISCST3 File for Ammonia Slip Emissions

```
** Building Downwash **
   BUILDHGT S008      14.20   14.20   14.20   14.20   14.20   14.20
   BUILDHGT S008      14.20   14.20   14.20   14.20   14.20   14.20
   BUILDHGT S008      14.20   14.20   14.20   14.20   14.20   14.20
   BUILDHGT S008      14.20   14.20   14.20   14.20   14.20   14.20
   BUILDHGT S008      14.20   14.20   14.20   14.20   14.20   14.20
   BUILDHGT S008      14.20   14.20   14.20   14.20   14.20   14.20

   BUILDHGT S009      14.20   14.20   14.20   14.20   14.20   14.20
   BUILDHGT S009      14.20   14.20   14.20   14.20   14.20   14.20
   BUILDHGT S009      14.20   14.20   14.20   14.20   14.20   14.20
   BUILDHGT S009      14.20   14.20   14.20   14.20   14.20   14.20
   BUILDHGT S009      14.20   14.20   14.20   14.20   14.20   14.20
   BUILDHGT S009      14.20   14.20   14.20   14.20   14.20   14.20

   BUILDWID S008      52.26   49.64   45.77   42.62   38.96   40.98
   BUILDWID S008      44.94   47.54   48.70   48.38   49.33   49.07
   BUILDWID S008      47.31   45.00   46.81   50.53   52.72   53.30
   BUILDWID S008      52.26   49.64   45.77   42.62   38.96   40.98
   BUILDWID S008      44.94   47.54   48.70   48.38   49.33   49.07
   BUILDWID S008      47.31   45.00   46.81   50.53   52.72   53.30

   BUILDWID S009      52.26   49.64   45.77   42.62   38.96   40.98
   BUILDWID S009      44.94   47.54   48.70   48.38   49.33   49.07
   BUILDWID S009      47.31   45.00   46.81   50.53   52.72   53.30
   BUILDWID S009      52.26   49.64   45.77   42.62   38.96   40.98
   BUILDWID S009      44.94   47.54   48.70   48.38   49.33   49.07
   BUILDWID S009      47.31   45.00   46.81   50.53   52.72   53.30



   SRCGROUP S008 S008
   SRCGROUP S009 S009
   SRCGROUP ALL
SO FINISHED
**
****************************************
** ISCST3 Receptor Pathway
****************************************
**
**
RE STARTING
   ELEVUNIT FEET
** DESCRREC "" ""
   DISCCART    412572.90   3727853.70   19.70
   DISCCART    412622.90   3727853.70   19.70
   DISCCART    412672.90   3727853.70   19.70

**The receptor list is abbreviated for space.  A full list of the receptors is available upon request.

RE FINISHED
**
****************************************
** ISCST3 Meteorology Pathway
****************************************
```

Table C-51 (Concluded)
Example ISCST3 File for Ammonia Slip Emissions

```
**
**
ME STARTING
   INPUTFIL C:\metdata\COSMESA.ASC
   ANEMHGHT 10 METERS
   SURFDATA 53126 1981
   UAIRDATA 91919 1981
ME FINISHED
**
****************************************
** ISCST3 Output Pathway
****************************************
**
**
OU STARTING
   RECTABLE ALLAVE 1ST
   RECTABLE 1 1ST
** Auto-Generated Plotfiles
** Plotfile Path: C:\Lakes\ISC-AERMODView\Projects\2007\PAR1110_2\OCSD1.IS\
   PLOTFILE 1 ALL 1ST OCSD1.IS\01H1GALL.PLT
   PLOTFILE PERIOD ALL OCSD1.IS\PE00GALL.PLT
OU FINISHED
```

Table C-52
Summary of Diesel Exhaust Emissions from Biogas Emergency Engines

Facility ID No.	Diesel PM, ton/year
29110	0.0186142
17301	0.0078784
9961	0.0022837
9163	0.0020946
001703	0.0019239
135216	0.0012418
3866	0.0011543
13088	0.000726
13433	0.0007106
11301	0.0006434
019159	0.0004719
1179	0.00026

Table C- 53
Summary of Diesel Exhaust Emissions from Non-Biogas Emergency Engines

Facility ID No.	Engine HP	TPY PM
Facility 1	31430	0.2467415
Facility 2	13272	0.0851537
Facility 3	12185	0.0782137
Facility 4	11191	0.0510922
Facility 5	3804	0.0323925
Facility 6	2425	0.0206498
Facility 7	1800	0.0153277
Facility 8	1760	0.0149871
Facility 9	2045	0.0146039
Facility 10	1580	0.0134543
Facility 11	1575	0.0134117
Facility 12	1535	0.0111551
Facility 13	2917	0.0100481
Facility 14	6813	0.0096309
Facility 15	1110	0.0094521
Facility 16	1055	0.0089837
Facility 17	1054	0.0089752
Facility 18	1008	0.0085835
Facility 19	1580	0.0084302
Facility 20	954	0.0081237
Facility 21	853	0.0072636
Facility 22	840	0.0071529
Facility 23	825	0.0070252
Facility 24	800	0.0068123
Facility 25	2875	0.0057479
Facility 26	2400	0.0057479
Facility 27	594	0.0050581
Facility 28	594	0.0050581
Facility 29	592	0.0050411
Facility 30	581	0.0049474
Facility 31	798	0.0048197
Facility 32	558	0.0047516
Facility 33	780	0.004726
Facility 34	545	0.0046409
Facility 35	512	0.0043599
Facility 36	500	0.0042577
Facility 37	500	0.0042577
Facility 38	468	0.0039852
Facility 39	460	0.0039171
Facility 40	740	0.0036616
Facility 41	567	0.0036616
Facility 42	427	0.0036361

Table C- 53 (Continued)
Summary of Diesel Exhaust Emissions from Non-Biogas Emergency Engines

Facility ID No.	Engine HP	TPY PM
Facility 43	412	0.0035083
Facility 44	400	0.0034061
Facility 45	400	0.0034061
Facility 46	395	0.0033636
Facility 47	395	0.0033636
Facility 48	395	0.0033636
Facility 49	880	0.003321
Facility 50	1161	0.0031507
Facility 51	369	0.0031422
Facility 52	348	0.0029633
Facility 53	755	0.0028101
Facility 54	330	0.0028101
Facility 55	330	0.0028101
Facility 56	3711	0.0027845
Facility 57	459	0.0026738
Facility 58	314	0.0026738
Facility 59	300	0.0025546
Facility 60	300	0.0025546
Facility 61	283	0.0024099
Facility 62	270	0.0022992
Facility 63	530	0.0022566
Facility 64	250	0.0021288
Facility 65	230	0.0019585
Facility 66	400	0.0017031
Facility 67	186	0.0015839
Facility 68	180	0.0015328
Facility 69	180	0.0015328
Facility 70	175	0.0014902
Facility 71	145	0.0012347
Facility 72	145	0.0012347
Facility 73	145	0.0012347
Facility 74	778	0.0012177
Facility 75	140	0.0011922
Facility 76	121	0.0010304
Facility 77	100	0.0008515
Facility 78	465	0.000843
Facility 79	94	0.0008004

Table C- 54
Summary of Ammonia Slip Emission

Facility ID No.	Ammonia Slip, ton/year	19% Ammonia Use, gal/year	Urea Use, gal/yr
Facility 1	0.13	1,065	298
Facility 2	0.13	1,052	294
Facility 3	0.45	3,598	1,007
Facility 4	0.78	6,194	1,734
Facility 5	0.62	4,939	1,383
Facility 6	0.38	3,034	849
Facility 7	0.42	3,352	938
Facility 8	1.68	13,324	3,730
Facility 9	3.38	26,869	7,521
Facility 10	0.67	5,337	1,494
Facility 11	0.33	2,603	729
Facility 12	1.77	14,067	3,938
Facility 13	1.66	13,152	3,681
Facility 14	0.64	5,108	1,430
Facility 15	0.09	748	209
Facility 16	0.34	2,732	765
Facility 17	1.39	11,026	3,086
Facility 18	0.81	6,444	1,804
Facility 19	0.34	2,667	747
Facility 20	0.04	308	86
Facility 21	0.06	455	127
Facility 22	0.16	1,237	346
Facility 23	2.08	16,540	4,630

Facilities listed in Table C-53 are not necessarily the same as in Table C-54.

Table C-55
Health Risk Calculations from Biogas Emergency Engines

Biogas Emergency Engine Carcinogenic Health Risk

Facility	No of Emerg ICEs	Single Unit Emissions, lb/yr	Facility DPM Emissions, ton/yr	Facility DPM Emissions, g/s	Cancer Potency Factor, (mg/kg-day)$^{-1}$	Daily Breathing Rate, L/kg-day	Exposure Frequency, day/year	Exposure Duration, year	Averaging Time, day	Modeled Conc, (ug/m3)/(g/s)	Carcinogenic Health Risk	Mitigated Carcinogenic Health Risk
Facility A	4	9	0.0186142	5.35E-04	1.10	302.00	350.00	70.00	2.56E+04	19.977	3.41E-06	5.11E-07
Facility B	2	8	0.0078784	2.27E-04	1.10	302.00	350.00	70.00	2.56E+04	5.49	3.96E-07	5.945E-08

Carcinogenic Health Risk = [DPM Emissions, g/s x Cancer Potency Factor, (mg/kg-day)$^{-}$1 x Daily Breathing Rate, L/kg-day x Exposure Frequency, hr/yr x Exposure Duration, yr x Modeled Conc., (ug/m3)/(g/s)]/(Averaging Time, day x 1,000,000 ug/mg)

Biogas Emergency Engine Chronic Non Carcinogenic Health Risk

Facility	No of Emergency ICEs	Single Unit Emissions, lb/yr	Facility DPM Emissions, ton/yr	Facility DPM Emissions, g/s	Reference Exposure Level, ug/m3	Modeled Conc, (ug/m3)/(g/s)	Chronic Hazard Index
Facility A	4	9	0.0186142	5.35E-04	5.00E+00	19.977	0.0021
Facility B	2	8	0.0078784	2.27E-04	5.00E+00	5.49	0.00025

Chronic Hazard Index = [Modeled Conc., (ug/m3)/(g/s)]/(Reference Exposure Level, ug/m3)
DPM target organ – Respiratory

Table C-56
Health Risk Calculations from Non-Biogas Emergency Engines

Non-Biogas Emergency Engine Carcinogenic Health Risk

Facility	Combined Facilty Engine Power,[a] bhp	Existing Engine Size,[b] bhp	Diesel Engine Replacement Size,[c] bhp	Number of Diesel Engines[d]	Receptor Distance,[e] m	ARB Single Engine Carcinogenic Health Risk[f] (millions)	Residential Carcinogenic Health Risk[g] (millions)	Worker Carcinogenic Health Risk[h] (millions)	MICR[i]	Mitigated MICR[j]	Chronic Hazard Index[k]
Facility C	28,976	five 5000, two 738	2,600	11	50	4	44.6	8.92	8.9		0.034
Facility D	10,000	five 2000	2,600	4	1,000	1	3.8	0.77	3.8		0.003
Facility E	11,175	3200, 3000, five 995	2,600	4	300	2	8.6	1.72	1.7		0.007
Facility F	6,000	three 2000	2,600, 750	two 2600, 750	40	4, 10	18.0	3.60	18.0	4.5	0.014
Facility G	3,804	six 634	2,600, 1,500	2,600, 1,500	30	12	12.0	2.40	2.4		0.009

a) Combined facility engine power - the sum of the bhp of the engines at a single facility
b) Existing engine size, bhp from survey information
c) Diesel engine replacement size was based on sizes available in the ARB "Hot Spots" Stationary Diesel Engine Screening Risk Assessment Tables (http://www.arb.ca.gov/ab2588/diesel/diesel.htm)
d) Number of engines is the number of ARB modeled engines that would be required to match the combined facility engine power. The largest stationary diesel emergency engine are around 3,000 bhp.
e) Receptor distances approximated from aerial photos on Google maps (www.maps.google.com)
f) Carcinogenic health risk associated with receptor distance and health risk in ARB diesel engine HRA tables for a single engine operating 50 hours per year.
g) Carcinogenic risk scaled to number of engines.
h) Worker carcinogenic health risk estimated by dividing residential heath risk by a factor of five.
i) The maximum exposed individual (residential or worker) based on information found in Google maps and Metrobot (http://streets.metrogbot.com)
j) ARB has validated diesel particulate filters for stationary ICE as at least 85 percent efficient.
k) Chronic HI = (residential carcinogenic health risk x AT)/(REF x CP x DBR x EF x ED), where AT = 25,550 days, diesel REF = 5 ug/m3, CP 1.1 mg/kg-day, DBR = 302 L/kg-day, EF = 350 days/year , ED = 70 years

Table C-57
ARB's Diesel Exhaust PM Risk (Potential Cancer Cases in a Million) for 750 BHP Engines

EF = 0.15 g/bhp-hr										
Downwind Distance (m)										
20	30	40	**50**	70	100	200	400	800	1200	1600
2	2	2	2	2	1	0	0	0	0	0
4	4	4	4	3	2	1	0	0	0	0
6	6	6	6	5	3	1	0	0	0	0
8	8	8	8	7	4	1	0	0	0	0
10	10	10	10	8	5	2	0	0	0	0
20	20	20	20	16	11	3	1	0	0	0
30	30	30	30	25	16	5	1	0	0	0
40	40	40	40	33	21	7	2	0	0	0
61	61	61	61	49	32	10	3	1	0	0
81	81	81	81	66	42	13	3	1	0	0
101	101	101	101	82	53	17	4	1	0	0
202	202	202	202	164	106	33	8	2	1	1

ARB "Hot Spots" Stationary Diesel Engine Screening Risk Assessment Tables (http://www.arb.ca.gov/ab2588/diesel/diesel.htm)

Table C-58
ARB's Diesel Exhaust PM Risk (Potential Cancer Cases in a Million) for 1,500 BHP Engines

EF = 0.15 g/bhp-hr														
Downwind Distance (m)														
20	30	40	50	60	70	80	90	100	200	300	400	800	1200	1600
2	2	2	2	2	2	2	2	1	1	0	0	0	0	0
3	3	3	3	3	3	3	3	3	2	1	0	0	0	0
5	5	5	5	5	5	5	5	4	2	1	1	0	0	0
6	6	6	6	6	6	6	6	6	3	2	1	0	0	0
8	8	8	8	8	8	8	8	7	4	2	1	0	0	0
15	15	15	15	15	15	15	15	15	8	4	2	1	0	0
23	23	23	23	23	23	23	23	22	12	6	4	1	0	0
30	30	30	30	30	30	30	30	30	16	8	5	1	1	0
45	45	45	45	45	45	45	45	45	24	12	7	2	1	1
60	60	60	60	60	60	60	60	60	31	16	10	2	1	1
75	75	75	75	75	75	75	75	75	39	20	12	3	1	1
151	151	151	151	151	151	151	151	150	78	41	24	6	3	2

ARB "Hot Spots" Stationary Diesel Engine Screening Risk Assessment Tables (http://www.arb.ca.gov/ab2588/diesel/diesel.htm)

Table C-59
ARB's Diesel Exhaust PM Risk (Potential Cancer Cases in a Million) for 2,600 BHP Engines

EF = 0.15 g/bhp-hr											
Downwind Distance (m)											
50	80	100	120	**150**	175	200	280	370	400	800	1600
1	1	1	1	1	1	1	1	0	0	0	0
2	2	2	2	2	2	2	1	1	1	0	0
3	3	3	3	3	3	3	2	1	1	0	0
4	4	4	4	4	4	3	2	2	1	0	0
4	4	4	4	4	4	4	3	2	2	1	0
9	9	9	9	9	9	8	6	4	4	1	0
13	13	13	13	13	13	12	9	6	5	2	1
18	18	18	18	18	17	16	12	8	7	2	1
26	26	26	26	26	26	25	18	12	11	3	1
35	35	35	35	35	35	33	24	16	14	4	1
44	44	44	44	44	44	41	30	20	18	5	2
88	88	88	88	88	87	82	59	40	36	10	3

ARB "Hot Spots" Stationary Diesel Engine Screening Risk Assessment Tables (http://www.arb.ca.gov/ab2588/diesel/diesel.htm)

Table C-60
Health Risk Calculations from Biogas SCR Ammonia Slip

Chronic Non-Carcinogenic Health Risk

Facility ID	No of Engines	Single Unit Emissions, lb/yr	Facility NH3 Emissions, ton/yr	X/Q, (ug/m3)/ (tons/yr)	Met Factor	Muti-Pathway Factor	Reference Exposure Level, ug/m3	Chronic Hazard Index
Facility A	5	2,255	5.637	49.68	0.69	1	2.00E+02	0.97

Chronic Hazard Index = (Facility DPM Emissions, ton/yr x X/Q, (ug/m3)/ (tons/yr) x Met Factor x Multi-Pathway Factor)/(Reference Exposure Level, ug/m3)

Acute Non-Carcinogenic Health Risk

Facility	No of Engines	Single Unit Emissions, lb/yr	Facility NH3 Emissions, lb/hr	X/Q, (ug/m3)/ (lb/hr)	Reference Exposure Level, ug/m3	Acute Hazard Index
Facility A	5	2,255	1.29	1000	3.20E+03	0.40

Acute Hazard Index = (Facility DPM Emissions, lb/hr x X/Q, (ug/m3)/ (lb/hr) x Met Factor x Multi-Pathway Factor)/(Reference Exposure Level, ug/m3)

Table C-61
LNG Calculations

Facility ID No.	Total LNG, MMBtu/year	Total LNG, gal/yr	LNG, gal/wk	LNG, gal/dy	LNG, cf/day	LNG, lb/day	LNG, lb/five days	LNG, gal/5 days
Facility 1	7,409	83,242	1,601	228	30	0	0	1,140
Facility 2	11,785	132,411	2,546	363	48	1,285	6,426	1,814
Facility 3	71,546	803,888	15,459	2,202	294	7,802	39,011	11,012
Facility 4	58,214	654,085	12,579	1,792	240	6,348	31,741	8,960
Facility 5	26,222	294,630	5,666	807	108	2,860	14,298	4,036
Facility 6	22,991	258,324	4,968	708	95	2,507	12,536	3,539
Facility 7	24,931	280,127	5,387	767	103	2,719	13,594	3,837
Facility 8	150,052	1,685,975	32,423	4,619	617	16,363	81,817	23,096
Facility 9	280,256	3,148,948	60,557	8,627	1,153	30,562	152,812	43,136
Facility 10	119,352	1,341,034	25,789	3,674	491	13,016	65,078	18,370
Facility 11	60,486	679,619	13,070	1,862	249	6,596	32,980	9,310
Facility 12	419,715	4,715,897	90,690	12,920	1,727	45,770	228,852	64,601
Facility 13	251,532	2,826,202	54,350	7,743	1,035	27,430	137,150	38,715
Facility 14	114,236	1,283,547	24,684	3,517	470	12,458	62,288	17,583
Facility 15	8,525	95,784	1,842	262	35	930	4,648	1,312
Facility 16	51,845	582,530	11,203	1,596	213	5,654	28,269	7,980
Facility 17	304,962	3,426,539	65,895	9,388	1,255	33,257	166,283	46,939
Facility 18	178,374	2,004,202	38,542	5,491	734	19,452	97,260	27,455
Facility 19	9,548	107,278	2,063	294	39	1,041	5,206	1,470
Facility 20	3,527	39,624	762	109	15	385	1,923	543
Facility 21	4,018	45,149	868	124	17	438	2,191	618
Facility 22	13,393	150,485	2,894	412	55	1,461	7,303	2,061
Facility 23	369,900	4,156,180	79,927	11,387	1,522	40,338	201,691	56,934
Total	2,562,817	28,712,460	552,163	78,664	10,516	278,671	1,393,355	393,321

89,000 Btu/gal
Facilities listed in Table C-61 are not necessarily the same as in Tables C-53 and C-54.

Table C-62
Health Risk Calculations from LNG Truck Delivery

Carcinogenic Health Risk

Facility DPM Emissions, ton/yr	X/Q, (ug/m3)/(tons /yr)	Met Factor	Annual Conc, Adjustment Factor	Daily Breathing Rate, L/kg-day	Exposure Value Factor	Muti-Pathway Factor	Cancer Potency Factor, , $(mg/kg\text{-}day)^{-1}$	Carcinogenic Health Risk
2.09E-06	2.98	1	1	302	0.96	1	1.1	1.99E-09

MICR = Cancer Potency Factor, $(mg/kg\text{-}day)^{-1}$ x Facility DPM Emissions, ton/year x X/Q, (g/m3)/(tons/yr)x Annual Conc, Adjustment Factor x Met Factor x Daily Breathing Rate, L/kg-day x Exposure Value Factor x Muti-Pathway Factor]/ (1,000,000 ug/mg)

Chronic Non-Carcinogenic Health Risk

Facility DPM Emissions, ton/yr	Facility, lb/hr	X/Q, (ug/m3)/ (tons/yr)	Met Factor	Reference Exposure Level, ug/m3	Met Factor	Chronic Hazard Index
2.09E-06	2.17E-04	41.45	1	5.00E+00	1	1.80E-03

Chronic Hazard Index = (Facility DPM Emissions, ton/yr x X/Q, (ug/m3)/ (tons/yr) x Met Factor x Multi-Pathway Factor)/(Reference Exposure Level, ug/m3)

Table C-63
Example RMP*COMP Input File for a Bermed Ammonia Storage Tank

RMP*Comp Ver. 1.07
Results of Consequence Analysis

Chemical: Ammonia (water solution) 20%
CAS #: 7664-41-7
Category: Toxic Liquid
Scenario: Worst-case
Quantity Released: 5500 gallons
Liquid Temperature: 25 C

Mitigation Measures:
Diked area: 267 square feet
Dike height: 3 feet

Release Rate to Outside Air: 5.61 pounds per minute
Topography: Rural surroundings (terrain generally flat and unobstructed)
Toxic Endpoint: 0.14 mg/L; basis: ERPG-2
Estimated Distance to Toxic Endpoint: 0.1 miles (0.2 kilometers)

--------Assumptions About This Scenario---------
Wind Speed: 1.5 meters/second (3.4 miles/hour)
Stability Class: F
Air Temperature: 77 degrees F (25 degrees C)

Table C-64
Example RMP*COMP Input File for a Bermed LNG Storage Tank

RMP*Comp Ver. 1.07
Results of Consequence Analysis

Chemical: Methane
CAS #: 74-82-8
Category: Flammable Gas
Scenario: Worst-case
Liquefied by refrigeration
Quantity Released: 71000 gallons
Release Type: Vapor Cloud Explosion
Mitigation Measures:
Diked area: 3480 square feet
Dike height: 3 feet

Release Rate to Outside Air: 731 pounds per minute
Quantity Evaporated in 10 Minutes: 7310 pounds
Estimated Distance to 1 psi overpressure: .2 miles (.3 kilometers)

Table C-64 (Concluded)
Example RMP*COMP Input File for a Bermed LNG Storage Tank

--------Assumptions About This Scenario---------
Wind Speed: 1.5 meters/second (3.4 miles/hour)
Stability Class: F
Air Temperature: 77 degrees F (25 degrees C)

Table C-65
Example RMP*COMP Input File for Delivery Truck

RMP*Comp Ver. 1.07
Results of Consequence Analysis

Chemical: Methane
CAS #: 74-82-8
Category: Flammable Gas
Scenario: Worst-case
Liquefied by refrigeration
Quantity Released: 10000 gallons
Release Type: Vapor Cloud Explosion
Mitigation Measures: NONE
Estimated Distance to 1 psi overpressure: .3 miles (.4 kilometers)

--------Assumptions About This Scenario---------
Wind Speed: 1.5 meters/second (3.4 miles/hour)
Stability Class: F
Air Temperature: 77 degrees F (25 degrees C)

Table C-66
Example RMP*COMP Input File for Delivery Truck Pool Fire

RMP*Comp Ver. 1.07
Results of Consequence Analysis

Chemical: Methane
CAS #: 74-82-8
Category: Flammable Gas
Scenario: Alternative
Liquefied by refrigeration
Release Duration: 1 minutes
Release Type: Pool Fire
Release Rate: 6000 gallons per min
Mitigation Measures: NONE
Topography: Rural surroundings (terrain generally flat and unobstructed)
Estimated Distance to Heat Radiation Endpoint (5 kilowatts/square meter): .2 miles (.3 kilometers)

Table C-66 (Concluded)
Example RMP*COMP Input File for Delivery Truck Pool Fire

--------Assumptions About This Scenario---------
Wind Speed: 3 meters/second (6.7 miles/hour)
Stability Class: D
Air Temperature: 77 degrees F (25 degrees C)

Table C-67
Example RMP*COMP Input File for Delivery Boiling Liquid Expanding Vapor Explosion

RMP*Comp Ver. 1.07
Results of Consequence Analysis

Chemical: Methane
CAS #: 74-82-8
Category: Flammable Gas
Scenario: Alternative
Liquefied by refrigeration
Release Type: BLEVE
Quantity in Fireball: 10000 gallons
Estimated Distance at which exposure may cause second-degree burns: .3 miles (.4 kilometers)

--------Assumptions About This Scenario---------
Wind Speed: 3 meters/second (6.7 miles/hour)
Stability Class: D
Air Temperature: 77 degrees F (25 degrees C)

Table C-68
LNG or NH3 Hypothetical* Accidental Release Impacts to Airports and Airfields

Airports	Estimated NH3 Tank Size (gal)	Estimated LNG Tank Size (gal)	Distance to Airport (mile)	Distance to Toxic Endpoint (mile)	Significant for NH3	Distance to 1 psi overpressure, (mile)	Significant for LNG
Riverside Municipal	5,500	4,500	0.51	0.01	No	0.06	No
Ontario International	5,500	10,000	0.92	0.01	No	0.08	No
San Bernardino International	5,500	11,000	0.52	0.01	No	0.09	No
Whiteman, LA County	5,500	71,000	1.45	0.01	No	0.2	No
Rialto Municipal	5,500	8,000	0.49	0.01	No	0.08	No
Ontario International	5,500	8,000	1.58	0.01	No	0.08	No
Chino Airport	5,500	1,500	0.32	0.01	No	0.04	No
Burbank	5,500	52,000	1.18	0.01	No	0.1	No
Whiteman, LA County	5,500	21,000	1.97	0.01	No	0.1	No

Note: Biogas facilities will either install add-on control and potential have NH3 adverse impacts or replace ICEs with LNG plants but not both. Therefore the adverse impacts would not overlap from the same facility. No biogas facility is within two miles of another.
*None of these facilities have indicated their compliance option.

Table C-69
LNG or NH3 Hypothetical* Accidental Release Impacts to Schools

Name of School	Estimated NH3 Tank Size (gal)	Estimated LNG Tank Size (gal)	Distance to School (mile)	Distance to Toxic Endpoint (mile)	Significant for NH3	Distance to 1 psi overpressure, (mile)	Significant for LNG
St. Edward the Confessor Parish	5,500	2,000	0.39	0.01	No	0.05	No
Capo Beach Calvary Schools			0.41	0.01	No	0.05	No
El Potrero Elementary	5,500	600	0.36	0.01	No	0.08	No

Note: Biogas facilities will either install add-on control and potential have NH3 adverse impacts or replace ICEs with LNG plants but not both. Therefore the adverse impacts would not overlap from the same facility. No biogas facility is within two miles of another.
*None of these facilities have indicated their compliance option.

Table C-70
LNG or NH3 Hypothetical* Accidental Release Impacts to Other Non-Residential Sensitive Receptors

Name of Sensitive Receptor	Estimated NH3 Tank Size (gal)	Estimated LNG Tank Size (gal)	Distance to School (mile)	Distance to Toxic Endpoint (mile)	Significant for NH3	Distance to 1 psi overpressure, (mile)	Significant for LNG
Childtime Children's Ctr	5,500	4,500	0.31	0.01	No	0.06	No

Note: Biogas facilities will either install add-on control and potential have NH3 adverse impacts or replace ICEs with LNG plants but not both. Therefore the adverse impacts would not overlap from the same facility. No biogas facility is within two miles of another.
*None of these facilities have indicated their compliance option.

Table C-71
Solid Waste Adverse Impacts

Upgrade Three-Way Catalyst	Install Cat Ox	Engines that May Be Electrified	Biogas Engines that May Be Replaced	SCR	Non-Biogas Electric Engine, lb	Biogas Electric Engine, lb	New Cat Ox, lb	New Cat Ox Number of Trucks Required	Upgrade Cat Ox, lb	Upgrade Number of Trucks Required	Carbon,, lb	Carbon No of Trucks Required	SCR, lb	SCR Number of Trucks Required
217	114	225	66	66	1,888,014	924,205	90,669	156	28,540	214	231,281	148	72,175	119

Solid and Hazardous Waste Disposed (in tons)

Description	Total	Upgrade	New Cat	SCR
Solid Waste	1,522			
Hazardous Waste Disposed		14.3	45.3	36.1

Table C-72
Alternative B Total Construction Criteria Emissions

SCR-Construction

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5 lb/day	CO2, ton/year
2008	89.8	42.1	12.0	0.08	5.0	4.6	630
2009	88.9	39.5	11.1	0.08	4.7	4.4	36.5
2010	141.4	61.8	17.6	0.13	7.4	6.9	203
2011	247	106	30.4	0.23	12.9	11.9	727
2012	52.5	22.3	6.4	0.05	2.7	2.5	73.0

Gas Turbines - Construction

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5 lb/day	CO2, ton/year
2008	89.8	42.1	12.0	0.08	5.0	4.6	630
2009	88.9	39.5	11.1	0.08	4.7	4.4	36.5
2010	141.4	61.8	17.6	0.13	7.4	6.9	203
2011	247	106	30.4	0.23	12.9	11.9	727
2012	52.5	22.3	6.4	0.05	2.7	2.5	73.0

Microturbines - Construction

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5 lb/day	CO2, ton/year
2008	89.8	42.1	12.0	0.08	5.0	4.6	630
2009	88.9	39.5	11.1	0.08	4.7	4.4	36.5
2010	141.4	61.8	17.6	0.13	7.4	6.9	203
2011	247	106	30.4	0.23	12.9	11.9	727
2012	52.5	22.3	6.4	0.05	2.7	2.5	73.0

Gas Turbines/LNG - Construction

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5 lb/day	CO2, ton/year
2008	89.8	42.1	12.0	0.08	5.0	4.6	630
2009	88.9	39.5	11.1	0.08	4.7	4.4	36.5
2010	141.4	61.8	17.6	0.13	7.4	6.9	203
2011	682	291	84.1	0.60	48.4	35.6	2,371
2012	488	206.6	60.2	0.43	38.3	26.2	1,718

Table C-72 (Concluded)
Alternative B Total Construction Criteria Emissions

Microturbines/LNG - Construction

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5 lb/day	CO_2, ton/year
2008	90	42.1	12.0	0.08	5.0	4.6	630
2009	88.9	39.5	11.1	0.08	4.7	4.4	36.5
2010	141.4	61.8	17.6	0.13	7.4	6.9	203
2011	682	291	84.1	0.60	48.4	35.6	2,371
2012	488	206.6	60.2	0.43	38.3	26.2	1,718

Table C-73
Alternative B Total Operational Criteria Emissions

SCR - Total Operational Emissions

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5 lb/day	~~CO_2, ton/year~~
Baseline	9,195	54,243	2,493	551	877	875	~~1,250,047~~
2008	~~8,999~~ 9,004	~~53,867~~ 53,900	~~2,458~~ 2,467	~~544~~ 545	~~872~~ 873	~~870~~ 871	~~1,227,230~~ -
2009	~~6,410~~ 6,415	~~22,399~~ 22,432	~~1,790~~ 1,799	~~543~~ 544	~~858~~ 859	~~856~~ 857	~~1,231,763~~ -
2010	~~5,862~~ 5,867	~~17,323~~ 17,356	~~1,280~~ 1,289	~~534~~ 535	~~837~~ 838	~~835~~ 836	~~1,208,248~~ -
2011	~~5,349~~ 5,354	~~13,511~~ 13,544	~~1,209~~ 1,218	~~528~~ 529	~~821~~ 822	~~819~~ 820	~~1,196,641~~ -
2012	4,129	13,459	1,013	538	830	829	~~1,231,572~~
2014	4,188	13,477	1,018	538	833	831	~~1,231,599~~

Gas Turbines - Total Operational Emissions

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5 lb/day	~~CO_2, ton/year~~
Baseline	9,195	54,243	2,493	551	877	875	~~1,250,047~~
2008	~~8,999~~ 9,004	~~53,867~~ 53,900	~~2,458~~ 2,467	~~544~~ 545	~~872~~ 873	~~870~~ 871	~~1,227,230~~ -
2009	~~6,410~~ 6,415	~~22,399~~ 22,432	~~1,790~~ 1,799	~~543~~ 544	~~858~~ 859	~~856~~ 857	~~1,231,763~~ -
2010	~~5,862~~ 5,867	~~17,323~~ 17,356	~~1,280~~ 1,289	~~534~~ 535	~~837~~ 838	~~835~~ 836	~~1,208,248~~ -
2011	~~5,343~~ 5,348	~~13,509~~ 13,542	~~1,209~~ 1,218	~~528~~ 529	~~821~~ 822	~~819~~ 820	~~1,196,710~~ -
2012	4,829	7,394	535	538	1,016	1,014	~~1,231,248~~
2014	4,888	7,412	540	538	1,019	1,017	~~1,231,248~~

Table C-73 (Contined)
Alternative B Total Operational Criteria Emissions

Microturbines - Total Operational Emissions

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5 lb/day	~~CO2, ton/year~~
Baseline	9,195	54,243	2,493	551	877	875	~~1,250,047~~
2008	~~8,999~~ 9,004	~~53,867~~ 53,900	~~2,458~~ 2,467	~~544~~ 545	~~872~~ 873	~~870~~ 871	~~1,227,230~~ -
2009	~~6,410~~ 6,415	~~22,399~~ 22,432	~~1,790~~ 1,799	~~543~~ 544	~~858~~ 859	~~856~~ 857	~~1,231,763~~ -
2010	~~5,862~~ 5,867	~~17,323~~ 17,356	~~1,280~~ 1,289	~~534~~ 535	~~837~~ 838	~~835~~ 836	~~1,208,248~~ -
2011	~~5,343~~ 5,348	~~13,509~~ 13,542	~~1,209~~ 1,218	~~528~~ 529	~~821~~ 822	~~819~~ 820	~~1,196,710~~ -
2012	3,864	6,206	641	538	757	756	~~1,231,362~~
2014	3,923	6,224	645	538	760	758	~~1,231,362~~

Gas Turbines/LNG - Total Operational Emissions

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5 lb/day	~~CO2, ton/year~~
Baseline	9,195	54,243	2,493	551	877	875	~~1,250,047~~
2008	~~8,999~~ 9,004	~~53,867~~ 53,900	~~2,458~~ 2,467	~~544~~ 545	~~872~~ 873	~~870~~ 871	~~1,227,230~~ -
2009	~~6,440~~ 6,445	~~23,215~~ 23,248	~~1,814~~ 1,823	~~543~~ 544	~~860~~ 861	~~858~~ 859	~~1,232,969~~ -
2010	~~5,862~~ 5,867	~~17,323~~ 17,356	~~1,280~~ 1,289	~~534~~ 535	~~837~~ 838	~~835~~ 836	~~1,208,248~~ -
2011	~~5,394~~ 5,399	~~13,525~~ 13,558	~~1,213~~ 1,222	~~528~~ 529	~~823~~ 824	~~821~~ 822	~~1,196,943~~ -
2012	4,258	6,539	526	211	872	870	~~1,093,200~~
2014	4,377	6,576	535	211	878	876	~~1,093,528~~

Table C-73 (Concluded)
Alternative B Total Operational Criteria Emissions

Microturbines/LNG - Total Operational Emissions

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5 lb/day	~~CO2, ton/year~~
Baseline	9,195	54,243	2,493	551	877	875	~~1,250,047~~
2008	~~8,999~~	~~53,867~~	~~2,458~~	~~544~~	~~872~~	~~870~~	~~1,227,230~~
	9,004	53,900	2,467	545	873	871	-
2009	~~6,410~~	~~22,399~~	~~1,790~~	~~543~~	~~858~~	~~856~~	~~1,231,763~~
	6,415	22,432	1,799	544	859	857	-
2010	~~5,862~~	~~17,323~~	~~1,280~~	~~534~~	~~837~~	~~835~~	~~1,208,248~~
	5,867	17,356	1,289	535	838	836	-
2011	~~5,394~~	~~13,525~~	~~1,213~~	~~528~~	~~823~~	~~821~~	~~1,196,943~~
	5,399	13,558	1,222	529	824	822	-
2012	3,874	6,075	572	211	767	765	~~1,093,308~~
2014	3,993	6,111	581	211	773	771	~~1,093,637~~

Table C-74
Alternative B Total Criteria Emissions

SCR - Total

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5 lb/day	CO2, ton/year
2008	~~9,089~~	~~53,909~~	~~2,470~~	~~543.9~~	~~876.8~~	~~874.7~~	~~1,227,861~~
	9,094	53,942	2,479	545	878	876	
2009	~~6,410~~	~~22,399~~	~~1,790~~	~~543~~	~~858~~	~~856~~	~~1,231,763~~
	6,415	22,432	1,799	544	859	857	
2010	~~6,004~~	~~17,385~~	~~1,297~~	~~534~~	~~844~~	~~842~~	~~1,208,451~~
	6,009	17,418	1,306	535	845	843	
2011	~~5,595~~	~~13,617~~	~~1,240~~	~~529~~	~~834~~	~~831~~	~~1,197,367~~
-	5,600	13,650	1,249	530	835	832	
2012	4,181	13,481	1,020	538	833	831	1,231,645
2014	4,188	13,477	1,018	538	833	831	1,231,599

Table C-74 (Continued)
Alternative B Total Criteria Emissions

Gas Turbines - Total

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5 lb/day	~~CO2, ton/year~~
2008	~~9,089~~ 9,094	~~53,909~~ 53,942	~~2,470~~ 2,479	~~543.9~~ 545	~~876.8~~ 878	~~874.7~~ 876	~~1,227,861~~
2009	~~6,410~~ 6,415	~~22,399~~ 22,432	~~1,790~~ 1,799	~~543~~ 544	~~858~~ 859	~~856~~ 857	~~1,231,763~~
2010	~~6,004~~ 6,009	~~17,385~~ 17,418	~~1,297~~ 1,306	~~534~~ 535	~~844~~ 845	~~842~~ 843	~~1,208,451~~
2011	~~5,589~~ 5,594	~~13,616~~ 13,649	~~1,239~~ 1,248	~~529~~ 530	~~833~~ 834	~~831~~ 832	~~1,197,436~~
2012	4,882	7,416	542	538	1,019	1,017	~~1,231,321~~
2014	4,888	7,412	540	538	1,019	1,017	~~1,231,248~~

Microturbines - Total

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5 lb/day	~~CO2, ton/year~~
2008	~~9,089~~ 9,094	~~53,909~~ 53,942	~~2,470~~ 2,479	~~543.9~~ 545	~~876.8~~ 878	~~874.7~~ 876	~~1,227,861~~
2009	~~6,410~~ 6,415	~~22,399~~ 22,432	~~1,790~~ 1,799	~~543~~ 544	~~858~~ 859	~~856~~ 857	~~1,231,763~~
2010	~~6,004~~ 6,009	~~17,385~~ 17,418	~~1,297~~ 1,306	~~534~~ 535	~~844~~ 845	~~842~~ 843	~~1,208,451~~
2011	~~5,589~~ 5,594	~~13,616~~ 13,649	~~1,239~~ 1,248	~~529~~ 530	~~833~~ 834	~~831~~ 832	~~1,197,436~~
2012	3,917	6,228	647	538	760	758	~~1,231,435~~
2014	3,923	6,224	645	538	760	758	~~1,231,362~~

Gas Turbines/LNG - Total

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5 lb/day	~~CO2, ton/year~~
2008	~~9,089~~ 9,094	~~53,909~~ 53,942	~~2,470~~ 2,479	~~543.9~~ 545	~~876.8~~ 878	~~874.7~~ 876	~~1,227,861~~
2009	~~6,410~~ 6,415	~~22,399~~ 22,432	~~1,790~~ 1,799	~~543~~ 544	~~858~~ 859	~~856~~ 857	~~1,231,763~~
2010	~~6,004~~ 6,009	~~17,385~~ 17,418	~~1,297~~ 1,306	~~534~~ 535	~~844~~ 845	~~842~~ 843	~~1,208,451~~
2011	~~6,076~~ 6,081	~~13,816~~ 13,849	~~1,297~~ 1,306	~~529~~ 530	~~872~~ 873	~~857~~ 858	~~1,199,314~~
2012	4,746	6,746	586	211	911	896	~~1,094,918~~
2014	4,377	6,576	535	211	878	876	~~1,093,528~~

Table C-74 (Concluded)
Alternative B Total Criteria Emissions

Microturbines/LNG - Total

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5 lb/day	~~CO2, ton/year~~
2008	~~9,089~~ 9,094	~~53,909~~ 53,942	~~2,470~~ 2,479	~~543.9~~ 545	~~876.8~~ 878	~~874.7~~ 876	~~1,231,763~~
2009	~~6,410~~ 6,415	~~22,399~~ 22,432	~~1,790~~ 1,799	~~543~~ 544	~~858~~ 859	~~856~~ 857	~~1,208,451~~
2010	~~6,004~~ 6,009	~~17,385~~ 17,418	~~1,297~~ 1,306	~~534~~ 535	~~844~~ 845	~~842~~ 843	~~1,199,314~~
2011	~~6,076~~ 6,081	~~13,816~~ 13,849	~~1,297~~ 1,306	~~529~~ 530	~~872~~ 873	~~857~~ 858	~~1,199,314~~
2012	4,362	6,281	632	211	805	791	~~1,095,026~~
2014	3,993	6,111	581	211	773	771	~~1,093,637~~

Table C-75
Alternative B Total Compared to Baseline

SCR - Total Compared to Baseline

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5 lb/day	~~CO2, ton/year~~
2008	~~(106)~~ (100)	~~(334)~~ (301)	~~(22)~~ (14)	~~(7.5)~~ (6.9)	~~(0.1)~~ 0.8	~~0.4~~ 0.4	~~(22,186)~~
2009	~~(3,191)~~ (3,185)	~~(36,858)~~ (36,825)	~~(1,196)~~ (1,187)	~~(17)~~ (17)	~~(33)~~ (32)	~~(33)~~ (32)	~~(41,596)~~
2010	~~(3,191)~~ (3,185)	~~(36,858)~~ (36,825)	~~(1,196)~~ (1,187)	~~(17)~~ (17)	~~(33)~~ (32)	~~(33)~~ (32)	~~(41,596)~~
2011	~~(3,600)~~ (3,594)	~~(40,626)~~ (40,593)	~~(1,253)~~ (1,244)	~~(23)~~ (22)	~~(43)~~ (42)	~~(44)~~ (43)	~~(52,679)~~
2012	(5,013)	(40,762)	(1,473)	(13)	(44)	(44)	~~(18,402)~~
2014	(5,007)	(40,766)	(1,475)	(13)	(44)	(44)	~~(18,448)~~

Table C-75 (Continued)
Alternative B Total Compared to Baseline

Gas Turbines - Total Compared to Baseline

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5 lb/day	~~CO2, ton/year~~
2008	~~(106)~~ (100)	~~(334)~~ (301)	~~(22)~~ (14)	~~(7.5)~~ (6.9)	~~(0.1)~~ 0.8	~~0.4~~ 0.4	~~(22,186)~~
2009	~~(3,191)~~ (3,185)	~~(36,858)~~ (36,825)	~~(1,196)~~ (1,187)	~~(17)~~ (17)	~~(33)~~ (32)	~~(33)~~ (32)	~~(41,596)~~
2010	~~(3,191)~~ (3,185)	~~(36,858)~~ (36,825)	~~(1,196)~~ (1,187)	~~(17)~~ (17)	~~(33)~~ (32)	~~(33)~~ (32)	~~(41,596)~~
2011	~~(3,605)~~ (3,600)	~~(40,627)~~ (40,594)	~~(1,253)~~ (1,245)	~~(23)~~ (22)	~~(43)~~ (43)	~~(44)~~ (43)	~~(52,610~~
2012	(4,313)	(46,827)	(1,951)	(13)	142	142	~~(18,725)~~
2014	(4,307)	(46,831)	(1,953)	(13)	142	142	~~(18,798)~~

Microturbines - Total Compared to Baseline

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5 lb/day	CO2, ton/year
2008	~~(106)~~ (100)	~~(334)~~ (301)	~~(22)~~ (14)	~~(7.5)~~ (6.9)	~~(0.1)~~ 0.8	~~0.4~~ 0.4	(22,186)
2009	~~(3,191)~~ (3,185)	~~(36,858)~~ (36,825)	~~(1,196)~~ (1,187)	~~(17)~~ (17)	~~(33)~~ (32)	~~(33)~~ (32)	(41,596)
2010	~~(3,191)~~ (3,185)	~~(36,858)~~ (36,825)	~~(1,196)~~ (1,187)	~~(17)~~ (17)	~~(33)~~ (32)	~~(33)~~ (32)	(41,596)
2011	~~(3,605)~~ (3,600)	~~(40,627)~~ (40,594)	~~(1,254)~~ (1,245)	~~(23)~~ (22)	~~(43)~~ (43)	~~(44)~~ (43)	(52,610)
2012	(5,278)	(48,015)	(1,846)	(13)	(117)	(117)	(18,611)
2014	(5,272)	(48,019)	(1,848)	(13)	(117)	(117)	(18,684)

Gas Turbines/LNG - Total Compared to Baseline

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5 lb/day	~~CO2, ton/year~~
2008	~~(106)~~ (100)	~~(334)~~ (301)	~~(22)~~ (14)	~~(7.5)~~ (6.9)	~~(0.1)~~ 0.8	~~0.4~~ 0.4	~~(22,186)~~
2009	~~(3,191)~~ (3,185)	~~(36,858)~~ (36,825)	~~(1,196)~~ (1,187)	~~(17)~~ (17)	~~(33)~~ (32)	~~(33)~~ (32)	~~(41,596)~~
2010	~~(3,191)~~ (3,185)	~~(36,858)~~ (36,825)	~~(1,196)~~ (1,187)	~~(17)~~ (17)	~~(33)~~ (32)	~~(33)~~ (32)	~~(41,596)~~
2011	~~(3,119)~~ (3,113)	~~(40,427)~~ (40,394)	~~(1,196)~~ (1,187)	~~(22)~~ (22)	~~(5)~~ (4)	~~(18)~~ (17)	~~(50,732)~~
2012	(4,449)	(47,497)	(1,907)	(340)	33.6	21.28	~~(155,129)~~
2014	(4,818)	(47,667)	(1,957)	(340)	1.2	0.73	~~(156,519)~~

Table C-75 (Concluded)
Alternative B Total Compared to Baseline

Microturbines/LNG - Total Compared to Baseline

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5 lb/day	~~CO_2, ton/year~~
2008	~~(106)~~ (100)	~~(334)~~ (301)	~~(22)~~ (14)	~~(7.5)~~ (6.9)	~~(0.1)~~ 0.8	~~0.4~~ 0.4	~~(22,186)~~
2009	~~(3,191)~~ (3,185)	~~(36,858)~~ (36,825)	~~(1,196)~~ (1,187)	~~(17)~~ (17)	~~(33)~~ (32)	~~(33)~~ (32)	~~(41,596~~
2010	~~(3,191)~~ (3,185)	~~(36,858)~~ (36,825)	~~(1,196)~~ (1,187)	~~(17)~~ (17)	~~(33)~~ (32)	~~(33)~~ (32)	~~(41,596~~
2011	~~(3,119)~~ (3,113)	~~(40,427)~~ (40,394)	~~(1,196)~~ (1,187)	~~(22)~~ (22)	~~(5)~~ (4)	~~(18)~~ (17)	~~(50,732)~~
2012	(4,833)	(47,962)	(1,861)	(340)	(72)	(84)	~~(155,020)~~
2014	(5,202)	(48,132)	(1,912)	(340)	(104)	(104)	~~(156,410)~~

Table C-76
Estimation of the Number of Electric Motor Replacements of Non-Biogas Engines Required for Alternative B to Be Carbon Neutral

SCR - Carbon Neutral Calculation

Description	Proposed Project CO_2, ton/year	No Electrification CO_2, ton/year	Reduction in CO_2 from Electrification	Average CO_2 Savings per Motor	Average No of Motor to Stay Carbon Neutral
Baseline					
2008	(22,186)	(22,186)	0		
2009	(41,596)	(23,363)	18,233		
2010	(41,596)	(23,363)	18,233		
2011	(52,679)	(22,016)	30,663		
2012	(18,402)	11,505	29,907		
2014	(18,448)	11,459	29,907		
2013-2018	(110,686)	68,753	179,439		
10 year total	(264,959)	11,516	276,475	1,636	8

Table C-76 (Continued)
Estimation of the Number of Electric Motor Replacements of Non-Biogas Engines Required for Alternative B to Be Carbon Neutral

Gas Turbines – Carbon Neutral Calculation

Description	Proposed Project CO2, ton/year	No Electrification CO2, ton/year	Reduction in CO2 from Electrification	Average CO2 Savings per Motor	Average No of Motor to Stay Carbon Neutral
Baseline					
2008	(22,186)	(22,186)	0		
2009	121,080	(23,363)	18,233		
2010	(41,596)	(23,363)	18,233		
2011	(52,610)	(21,947)	30,663		
2012	(18,725)	11,181	29,907		
2014	(18,798)	11,108	29,907		
2013-2018	(112,790)	66,649	179,439		
10 year total	(104,642)	9,157	113,799	673	14

Microturbines – Carbon Neutral Calculation

Description	Proposed Project CO2, ton/year	No Electrification CO2, ton/year	Reduction in CO2 from Electrification	Average CO2 Savings per Motor	Average No of Motor to Stay Carbon Neutral
Baseline					
2008	(22,186)	(22,186)	0		
2009	(41,596)	(23,363)	18,233		
2010	(41,596)	(23,363)	18,233		
2011	(52,610)	(21,947)	30,663		
2012	(18,611)	11,295	29,907		
2014	(18,684)	11,222	29,907		
2013-2018	(112,106)	67,333	179,439		
10 year total	(266,520)	9,955	276,475	1,636	7

Table C-76 (Concluded)
Estimation of the Number of Electric Motor Replacements of Non-Biogas Engines Required for Alternative B to Be Carbon Neutral

Gas Turbines/LNG - Carbon Neutral Calculation

Description	Proposed Project CO2, ton/year	No Electrification CO2, ton/year	Reduction in CO2 from Electrification	Average CO2 Savings per Motor	Average No of Motor to Stay Carbon Neutral
Baseline					
2008	(22,186)	(22,186)	0		
2009	(41,596)	(23,363)	18,233		
2010	(41,596)	(23,363)	18,233		
2011	(50,732)	(20,069)	30,663		
2012	(155,129)	(125,222)	29,907		
2014	(156,519)	(126,612)	29,907		
2013-2018	(939,112)	(759,672)	179,439		
10 year total	(1,228,165)	(951,690)	276,475	1,636	0

Microturbines/LNG - Carbon Neutral Calculation

Description	Proposed Project CO2, ton/year	No Electrification CO2, ton/year	Reduction in CO2 from Electrification	Average CO2 Savings per Motor	Average No of Motor to Stay Carbon Neutral
Baseline					
2008	(22,186)	(22,186)	0		
2009	(41,596)	(23,363)	18,233		
2010	(41,596)	(23,363)	18,233		
2011	(50,732)	(20,069)	30,663		
2012	(155,020)	(125,114)	29,907		
2014	(156,410)	(126,504)	29,907		
2013-2018	(938,462)	(759,022)	179,439		
10 year total	(1,227,406)	(950,932)	276,475	1,636	0

Table C-77
Summary of the Number of Electric Motor Replacements of Non-Biogas Engines Required for Alternative B to Be Carbon Neutral

Description	**Proposed Project CO2, ton/year**	**No Electrification CO2, ton/year**	**Reduction in CO2 from Electrification**	**Average CO2 Savings per Motor**	**Average No of Motor to Stay Carbon Neutral**
SCR	(264,959)	11,516	276,475	1,636	8
Replace ICE with Gas Turbine	(104,642)	9,157	113,799	673	14
Replace ICE Microturbine	(266,520)	9,955	276,475	1,636	7
Replace LFG w LNG, DG w Turbines	(1,228,165)	(951,690)	276,475	1,636	0
Replace LFG w LNG, DG w Microturbines	(1,227,406)	(950,932)	276,475	1,636	0

Table C-78
Summary of Alternative B Energy Effects Compared to Baseline

Description	**Natural Gas Consumption, MMBtu/yr**	**Electricity Consumption, MWH/yr**	**Shaft Work Produced, Hp-Hrs/yr**	**Diesel Fuel Consumption, gal/yr**	**LNG Production, MMBtu/yr**
SCR	(544,398)	174,100	(59,006)	31,152	
Gas Turbines	(474,039)	229,556	(15,123,937)	38,128	
Micro Turbines	(428,481)	273,408	(15,123,937)	41,241	
Gas Turbines/LNG	(201,395)	558,557	(15,123,937)	38,128	2,374,019
Microturbines/LNG	(181,719)	576,527	(15,123,937)	57,364	2,374,019

Table C-79
Number of Engines Affected by Alternative C

Engines	**2008**	**2009**	**2010**	**2011**	**Total**
Begin Increased Source Testing	473				**473**
Begin Inspection & Monitoring	473				**473**
Install Sampling Infrastructure	503				**503**
Install AFRC		34			**34**
Install CEMS - Engine Count		9	28	32	**69**
Install CEMS - CEMS Count		4	10	10	**24**
Install CO Analyzer			34	14	**48**

Table C-80
Number of Facilities Affected by Alternative C

Facilities	2008	2009	2010	2011	Total
Begin Increased Source Testing	242				**242**
Begin Inspection & Monitoring	242				**242**
Install Sampling Infrastructure	240				**240**
Install AFRC		16			**16**
Install CEMS		4	10	10	**24**
Install CO Analyzer			15	5	**20**

Table C-81
Alternative C Total Construction Emissions

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5 lb/day	CO2, ton/year
2008	119.7	56.2	16.0	0.11	6.6	6.1	790
2009	36.4	17.1	4.7	0.03	2.0	1.8	19.2
2010	36.4	17.1	4.7	0.03	2.0	1.8	31
2011	36	17	4.7	0.03	2.0	1.8	33

Table C-82
Alternative C Total Criteria Operational Emissions

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5 lb/day	CO2, ton/year
2005 Baseline	9,195	54,243	2,493	551	877	875	~~1,250,047~~
2008	~~9,032~~ <u>9,035</u>	~~54,030~~ <u>54,048</u>	~~2,473~~ <u>2,478</u>	~~547~~ <u>547</u>	~~874~~ <u>874</u>	~~872~~ <u>872</u>	~~1,237,072~~
2009	~~6,853~~ <u>6,856</u>	~~22,683~~ <u>22,701</u>	~~1,848~~ <u>1,853</u>	~~547~~ <u>547</u>	~~874~~ <u>874</u>	~~872~~ <u>872</u>	~~1,246,022~~
2010	~~6,828~~ <u>6,831</u>	~~22,216~~ <u>22,234</u>	~~1,514~~ <u>1,519</u>	~~545~~ <u>545</u>	~~872~~ <u>872</u>	~~871~~ <u>871</u>	~~1,238,771~~
2011	~~6,784~~ <u>6,787</u>	~~21,972~~ <u>21,990</u>	~~1,512~~ <u>1,517</u>	~~545~~ <u>545</u>	~~872~~ <u>872</u>	~~871~~ <u>871</u>	~~1,238,841~~

Table C-83
Alternative C Total Criteria Emissions

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5 lb/day	~~CO2, ton/year~~
2008	~~9,152~~ 9,155	~~54,086~~ 54,104	~~2,489~~ 2,494	~~547~~ 547	~~880.8~~ 881.3	~~878.6~~ 879.1	~~1,237,862~~
2009	~~6,853~~ 6,856	~~22,683~~ 22,701	~~1,848~~ 1,853	~~547~~ 547	~~874.0~~ 874.5	~~872.0~~ 872.5	~~1,246,022~~
2010	~~6,864~~ 6,867	~~22,233~~ 22,251	~~1,519~~ 1,524	~~545~~ 545	~~874.0~~ 874.5	~~872.0~~ 872.5	~~1,238,803~~
2011	~~6,820~~ 6,823	~~21,989~~ 22,007	~~1,517~~ 1,522	~~545~~ 545	~~874.0~~ 874.5	~~872.0~~ 872.5	~~1,238,875~~

Table C-84
Alternative C Total Compared to Baseline

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5 lb/day	~~CO2, ton/year~~
2008	~~(43)~~ (40)	~~(157)~~ (139)	~~(3)~~ 1	~~(5)~~ (4)	~~3.9~~ 4.4	~~3.4~~ 3.9	~~(12,184)~~
2009	~~(2,331)~~ (2,339)	~~(32,010)~~ (31,542)	~~(974)~~ (640)	~~(6)~~ (4)	~~(3)~~ (2.4)	~~(3)~~ (2.7)	~~(11,244)~~
2010	~~(2,331)~~ (2,328)	~~(32,010)~~ (31,992)	~~(974)~~ (969)	~~(6)~~ (6)	~~(3)~~ (2.4)	~~(3)~~ (2.7)	~~(11,244)~~
2011	~~(2,375)~~ (2,372)	~~(32,254)~~ (32,236)	~~(976)~~ (971)	~~(6)~~ (6)	~~(3)~~ (2.4)	~~(3)~~ (2.7)	~~(11,172)~~

Table C-85
Summary of Alternative C Energy Effects Compared Baseline

Natural Gas Consumption, MMBtu/yr	Electricity Consumption, MWH/yr	Diesel Fuel Consumption, gal/yr
0	2,273	32,528

Table C-86
Alternative D Total Construction Emissions

SCR - Construction

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5 lb/day	CO2, ton/year
2008	89.8	42.1	12.0	0.08	5.0	4.6	630
2009	88.9	39.5	11.1	0.08	4.7	4.4	36.5
2010	141.4	61.8	17.6	0.13	7.4	6.9	203
2011	247	106	30.4	0.23	12.9	11.9	727
2012	52.5	22.3	6.4	0.05	2.7	2.5	73.0

Gas Turbines - Construction

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5 lb/day	CO2, ton/year
2008	89.8	42.1	12.0	0.08	5.0	4.6	630
2009	88.9	39.5	11.1	0.08	4.7	4.4	36.5
2010	141.4	61.8	17.6	0.13	7.4	6.9	203
2011	247	106	30.4	0.23	12.9	11.9	727
2012	52.5	22.3	6.4	0.05	2.7	2.5	73.0

Microturbines - Construction

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5 lb/day	CO2, ton/year
2008	89.8	42.1	12.0	0.08	5.0	4.6	630
2009	88.9	39.5	11.1	0.08	4.7	4.4	36.5
2010	141.4	61.8	17.6	0.13	7.4	6.9	203
2011	247	106	30.4	0.23	12.9	11.9	727
2012	52.5	22.3	6.4	0.05	2.7	2.5	73.0

Gas Turbines/LNG - Construction

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5 lb/day	CO2, ton/year
2008	89.8	42.1	12.0	0.08	5.0	4.6	630
2009	88.9	39.5	11.1	0.08	4.7	4.4	36.5
2010	141.4	61.8	17.6	0.13	7.4	6.9	203
2011	682	291	84.1	0.60	48.4	35.6	2,371
2012	488	206.6	60.2	0.43	38.3	26.2	1,718

Table C-86 (Concluded)
Alternative D Total Construction Emissions

Microturbines/LNG - Construction

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5 lb/day	CO2, ton/year
2008	90	42.1	12.0	0.08	5.0	4.6	630
2009	88.9	39.5	11.1	0.08	4.7	4.4	36.5
2010	141.4	61.8	17.6	0.13	7.4	6.9	203
2011	682	291	84.1	0.60	48.4	35.6	2,371
2012	488	206.6	60.2	0.43	38.3	26.2	1,718

Table C-87
Alternative D Total Criteria Operational Emissions

SCR - Total Operational Emissions

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5 lb/day	~~CO2, ton/year~~
2005 Baseline	9,195	54,243	2,493	551	877	875	~~1,250,047~~
2008	~~8,999~~ 9,004	~~53,867~~ 53,900	~~2,458~~ 2,467	~~544~~ 545	~~872~~ 873	~~870~~ 871	~~1,227,230~~
2009	~~6,410~~ 6,415	~~22,399~~ 22,432	~~1,790~~ 1,799	~~543~~ 544	~~858~~ 859	~~856~~ 857	~~1,231,763~~
2010	~~5,823~~ 5,828	~~15,757~~ 15,790	~~1,250~~ 1,259	~~534~~ 535	~~837~~ 838	~~835~~ 836	~~1,208,312~~
2011	~~5,345~~ 5,350	~~11,627~~ 11,660	~~1,169~~ 1,178	~~528~~ 529	~~821~~ 822	~~819~~ 820	~~1,197,181~~
2012	4,125	5,748	627	538	830	829	1233796
2014	4,184	5,766	632	538	833	831	1233823

Table C-87Continued)
Alternative D Total Criteria Operational Emissions

Gas Turbines - Total Operational Emissions

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5 lb/day	~~CO2, ton/year~~
2005 Baseline	9,195	54,243	2,493	551	877	875	~~1,250,047~~
2008	~~8,999~~ 9,004	~~53,867~~ 53,900	~~2,458~~ 2,467	~~544~~ 545	~~872~~ 873	~~870~~ 871	~~1,227,230~~
2009	~~6,410~~ 6,415	~~22,399~~ 22,432	~~1,790~~ 1,799	~~543~~ 544	~~858~~ 859	~~856~~ 857	~~1,231,763~~
2010	~~5,823~~ 5,828	~~15,757~~ 15,790	~~1,250~~ 1,259	~~534~~ 535	~~837~~ 838	~~835~~ 836	~~1,208,312~~
2011	~~5,339~~ 5,344	~~11,625~~ 11,658	~~1,169~~ 1,178	~~528~~ 529	~~821~~ 822	~~819~~ 820	~~1,197,250~~
2012	4,825	5,509	495	538	1016	1014	~~1,231,801~~
2014	4,884	5,527	500	538	1019	1017	~~1,231,801~~

Microturbines - Total Operational Emissions

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5 lb/day	~~CO2, ton/year~~
2005 Baseline	9,195	54,243	2,493	551	877	875	~~1,250,047~~
2008	~~8,999~~ 9,004	~~53,867~~ 53,900	~~2,458~~ 2,467	~~544~~ 545	~~872~~ 873	~~870~~ 871	~~1,227,230~~
2009	~~6,410~~ 6,415	~~22,399~~ 22,432	~~1,790~~ 1,799	~~543~~ 544	~~858~~ 859	~~856~~ 857	~~1,231,763~~
2010	~~5,823~~ 5,828	~~15,757~~ 15,790	~~1,250~~ 1,259	~~534~~ 535	~~837~~ 838	~~835~~ 836	~~1,208,312~~
2011	~~5,339~~ 5,344	~~11,625~~ 11,658	~~1,169~~ 1,178	~~528~~ 529	~~821~~ 822	~~819~~ 820	~~1,197,250~~
2012	3,860	4,321	600	538	757	756	~~1,231,915~~

Table C-87 (Concluded)
Alternative D Total Criteria Operational Emissions

Gas Turbines/LNG - Total Operational Emissions

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5 lb/day	~~CO2, ton/year~~
2005 Baseline	9,195	54,243	2,493	551	877	875	~~1,250,047~~
2008	~~8,999~~ 9,004	~~53,867~~ 53,900	~~2,458~~ 2,467	~~544~~ 545	~~872~~ 873	~~870~~ 871	~~1,227,230~~
2009	~~6,440~~ 6,445	~~23,215~~ 23,248	~~1,814~~ 1,823	~~543~~ 544	~~860~~ 861	~~858~~ 859	~~1,232,969~~
2010	~~5,823~~ 5,828	~~15,757~~ 15,790	~~1,250~~ 1,259	~~534~~ 535	~~837~~ 838	~~835~~ 836	~~1,208,312~~
2011	~~5,390~~ 5,395	~~11,640~~ 11,673	~~1,173~~ 1,182	~~528~~ 529	~~823~~ 824	~~821~~ 822	~~1,197,500~~
2012	4,254	4,655	486	211	872	870	~~1,093,753~~
2014	4,373	4,692	495	211	878	876	~~1,094,081~~

Microturbines/LNG - Total Operational Emissions

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5 lb/day	~~CO2, ton/year~~
2005 Baseline	9,195	54,243	2,493	551	877	875	~~1,250,047~~
2008	~~8,999~~ 9,004	~~53,867~~ 53,900	~~2,458~~ 2,467	~~544~~ 545	~~872~~ 873	~~870~~ 871	~~1,227,230~~
2009	~~6,410~~ 6,415	~~22,399~~ 22,432	~~1,790~~ 1,799	~~543~~ 544	~~858~~ 859	~~856~~ 857	~~1,231,763~~
2010	~~5,823~~ 5,828	~~15,757~~ 15,790	~~1,250~~ 1,259	~~534~~ 535	~~837~~ 838	~~835~~ 836	~~1,208,312~~
2011	~~5,390~~ 5,395	~~11,640~~ 11,673	~~1,173~~ 1,182	~~528~~ 529	~~823~~ 824	~~821~~ 822	~~1,197,500~~
2012	3,870	4,190	531	211	767	765	~~1,093,861~~
2014	3,989	4,227	541	211	773	771	~~1,094,189~~

Table C-88
Alternative D Total Criteria Emissions

SCR - Total

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5 lb/day	~~CO2, ton/year~~
2008	~~9,089~~ 9,094	~~53,909~~ 53,942	~~2,470~~ 2,479	~~543.9~~ 545	~~876.8~~ 878	~~874.7~~ 876	~~1,227,861~~
2009	~~6,410~~ 6,415	~~22,399~~ 22,432	~~1,790~~ 1,799	~~543~~ 544	~~858~~ 859	~~856~~ 857	~~1,231,763~~
2010	~~5,964~~ 5,969	~~15,818~~ 15,851	~~1,267~~ 1,276	~~534~~ 535	~~844~~ 845	~~842~~ 843	~~1,208,515~~
2011	~~5,591~~ 5,596	~~11,733~~ 11,766	~~1,200~~ 1,209	~~529~~ 530	~~834~~ 835	~~831~~ 832	~~1,197,908~~
2012	~~4,178~~	~~5,770~~	~~634~~	~~538~~	~~833~~	~~831~~	~~1,233,869~~
	5,420	11,657	1,177	528	825	823	
2014	~~4,184~~	~~5,766~~	~~632~~	~~538~~	~~833~~	~~831~~	~~1,233,823~~
	3,706	3,504	425	74	697	696	
2015	3,712	3,500	423	74	697	696	

Gas Turbines - Total

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5 lb/day	~~CO2, ton/year~~
2008	~~9,089~~ 9,094	~~53,909~~ 53,942	~~2,470~~ 2,479	~~543.9~~ 545	~~876.8~~ 878	~~874.7~~ 876	~~1,227,861~~
2009	~~6,410~~ 6,415	~~22,399~~ 22,432	~~1,790~~ 1,799	~~543~~ 544	~~858~~ 859	~~856~~ 857	~~1,231,763~~
2010	~~5,964~~ 5,969	~~15,818~~ 15,851	~~1,267~~ 1,276	~~534~~ 535	~~844~~ 845	~~842~~ 843	~~1,208,515~~
2011	~~5,586~~ 5,591	~~11,731~~ 11,764	~~1,199~~ 1,208	~~529~~ 530	~~833~~ 834	~~831~~ 832	~~1,197,977~~
2012	5,444	11,784	1,189	529	832	830	~~1,231,874~~
2014	4,878	5,532	502	538	1,019	1,017	~~1,231,801~~
2015	4,884	5,527	500	538	1,019	1,017	

Table C-88 (Continued)
Alternative D Total Criteria Emissions

Microturbines - Total

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5 lb/day	~~CO2, ton/year~~
2008	~~9,089~~ 9,094	~~53,909~~ 53,942	~~2,470~~ 2,479	~~543.9~~ 545	~~876.8~~ 878	~~874.7~~ 876	~~1,227,861~~
2009	~~6,410~~ 6,415	~~22,399~~ 22,432	~~1,790~~ 1,799	~~543~~ 544	~~858~~ 859	~~856~~ 857	~~1,231,763~~
2010	~~5,964~~ 5,969	~~15,818~~ 15,851	~~1,267~~ 1,276	~~534~~ 535	~~844~~ 845	~~842~~ 843	~~1,208,515~~
2011	~~5,586~~ 5,591	~~11,731~~ 11,764	~~1,199~~ 1,208	~~529~~ 530	~~833~~ 834	~~831~~ 832	~~1,197,977~~
2012	5,463	11,854	1,196	529	837	835	~~1,231,988~~
2014	3,913	4,344	607	538	760	758	~~1,231,915~~
2015	3,919	4,339	605	538	760	758	

Gas Turbines/LNG - Total

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5 lb/day	~~CO2, ton/year~~
2008	~~9,089~~ 9,094	~~53,909~~ 53,942	~~2,470~~ 2,479	~~543.9~~ 545	~~876.8~~ 878	~~874.7~~ 876	~~1,227,861~~
2009	~~6,410~~ 6,415	~~22,399~~ 22,432	~~1,790~~ 1,799	~~543~~ 544	~~858~~ 859	~~856~~ 857	~~1,231,763~~
2010	~~5,964~~ 5,969	~~15,818~~ 15,851	~~1,267~~ 1,276	~~534~~ 535	~~844~~ 845	~~842~~ 843	~~1,208,515~~
2011	~~6,072~~ 6,077	~~11,931~~ 11,964	~~1,257~~ 1,266	~~529~~ 530	~~872~~ 873	~~857~~ 858	~~1,199,871~~
2012	5,944	12,230	1,267	529	896	882	~~1,095,471~~
2014	4,742	4,862	546	211	911	896	~~1,094,081~~
2015	4,373	4,692	495	211	878	876	

Table C-88 (Concluded)
Alternative D Total Criteria Emissions

Microturbines/LNG - Total

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5 lb/day	~~CO2, ton/year~~
2008	~~9,089~~ 9,094	~~53,909~~ 53,942	~~2,470~~ 2,479	~~543.9~~ 545	~~876.8~~ 878	~~874.7~~ 876	~~1,227,861~~
2009	~~6,410~~ 6,415	~~22,399~~ 22,432	~~1,790~~ 1,799	~~543~~ 544	~~858~~ 859	~~856~~ 857	~~1,231,763~~
2010	~~5,964~~ 5,969	~~15,818~~ 15,851	~~1,267~~ 1,276	~~534~~ 535	~~844~~ 845	~~842~~ 843	~~1,208,515~~
2011	~~6,072~~ 6,077	~~11,931~~ 11,964	~~1,257~~ 1,266	~~529~~ 530	~~872~~ 873	~~857~~ 858	~~1,199,871~~
2012	5,963	12,280	1,272	529	899	885	~~1,095,579~~
2014	4,206	3,707	483	75	736	722	~~1,094,189~~
2015	3,837	3,537	433	74	703	702	

Table C-89
Alternative D Total Compared to Baseline

SCR - Total Compared to Baseline

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5 lb/day	~~CO2, ton/year~~
2008	~~(106)~~ (100)	~~(334)~~ (301)	~~(22)~~ (14)	~~(7.5)~~ (6.9)	~~(0.1)~~ 0.8	~~0.4~~ 0.4	~~(22,186)~~
2009	~~(3,231)~~ (3,225)	~~(38,425)~~ (38,392)	~~(1,226)~~ (1,217)	~~(18)~~ (17)	~~(33)~~ (32)	~~(33)~~ (32)	~~(41,531)~~
2010	~~(3,231)~~ (3,225)	~~(38,425)~~ (38,392)	~~(1,226)~~ (1,217)	~~(18)~~ (17)	~~(33)~~ (32)	~~(33)~~ (32)	~~(41,531)~~
2011	~~(3,603)~~ (3,598)	~~(42,510)~~ (42,477)	~~(1,293)~~ (1,284)	~~(23)~~ (22)	~~(43)~~ (42)	~~(44)~~ (43)	~~(52,139)~~
2012	~~(5,017)~~	~~(48,473)~~	~~(1,859)~~	~~(13)~~	~~(44)~~	~~(44)~~	~~(16,178)~~
	(3,775)	(42,586)	(1,315)	(23)	(52)	(52)	
2014	~~(5,011)~~	~~(48,477)~~	~~(1,861)~~	~~(13)~~	~~(44)~~	~~(44)~~	~~(16,224)~~
	(5,489)	(50,739)	(2,068)	(477)	(180)	(180)	
2015	(5,483)	(50,743)	(2,070)	(477)	(179)	(179)	

Table C-89 (Continued)
Alternative D Total Compared to Baseline

Gas Turbines - Total Compared to Baseline

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5 lb/day	~~CO_2, ton/year~~
2008	~~(106)~~ (100)	~~(334)~~ (301)	~~(23)~~ (14)	~~(7.5)~~ (6.9)	~~(0.1)~~ 0.8	~~0.4~~ 0.4	~~(22,186)~~
2009	~~(3,231)~~ (3,225)	~~(38,425)~~ (38,392)	~~(1,194)~~ (1,217)	~~(18)~~ (17)	~~(33)~~ (32)	~~(33)~~ (32)	~~(41,531)~~
2010	~~(3,231)~~ (3,225)	~~(38,425)~~ (38,392)	~~(1,226)~~ (1,217)	~~(18)~~ (17)	~~(33)~~ (32)	~~(33)~~ (32)	~~(41,531)~~
2011	~~(3,609)~~ (3,603)	~~(42,512)~~ (42,479)	~~(1,294)~~ (1,285)	~~(23)~~ (22)	~~(43)~~ (43)	~~(44)~~ (43)	~~(52,070)~~
2012	(3,751)	(42,459)	(1,304)	(23)	(44)	(45)	
2014	(4,317)	(48,711)	(1,991)	(13)	142	142	~~(18,173)~~
2015	(4,311)	(48,716)	(1,993)	(13)	142	142	~~(18,246)~~

Microturbines - Total Compared to Baseline

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5 lb/day	~~CO_2, ton/year~~
2008	~~(106)~~ (100)	~~(334)~~ (301)	~~(22)~~ (14)	~~(7.5)~~ (6.9)	~~(0.1)~~ 0.8	~~0.4~~ 0.4	~~(22,186)~~
2009	~~(3,231)~~ (3,225)	~~(38,425)~~ (38,392)	~~(1,226)~~ (1,217)	~~(18)~~ (17)	~~(33)~~ (32)	~~(33)~~ (32)	~~(41,531)~~
2010	~~(3,231)~~ (3,225)	~~(38,425)~~ (38,392)	~~(1,226)~~ (1,217)	~~(18)~~ (17)	~~(33)~~ (32)	~~(33)~~ (32)	~~(41,531)~~
2011	~~(3,609)~~ (3,603)	~~(42,512)~~ (42,479)	~~(1,294)~~ (1,285)	~~(23)~~ (22)	~~(43)~~ (43)	~~(44)~~ (43)	~~(52,070)~~
2012	~~(5,282)~~	~~(49,899)~~	~~(1,886)~~	~~(13)~~	~~(117)~~	~~(117)~~	~~(18,059)~~
	(3,732)	(49,389)	(1,297)	(22)	(40)	(40)	
2014	~~(5,275)~~	~~(49,904)~~	~~(1,888)~~	~~(13)~~	~~(117)~~	~~(117)~~	~~(18,132)~~
	(5,282)	(49,899)	(1,886)	(13)	(117)	(117)	
2015	(5,275)	(49,904)	(1,888)	(13)	(117)	(117)	

Table C-89 (Concluded)
Alternative D Total Compared to Baseline

Gas Turbines/LNG - Total Compared to Baseline

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5 lb/day	~~CO_2, ton/year~~
2008	~~(106)~~ (100)	~~(334)~~ (301)	~~(22)~~ (14)	~~(7.5)~~ (6.9)	~~(0.1)~~ 0.8	~~0.4~~ 0.4	~~(22,186)~~
2009	~~(3,231)~~ (3,225)	~~(38,425)~~ (38,392)	~~(1,226)~~ (1,217)	~~(18)~~ (17)	~~(33)~~ (32)	~~(33)~~ (32)	~~(41,531)~~
2010	~~(3,231)~~ (3,225)	~~(38,425)~~ (38,392)	~~(1,226)~~ (1,217)	~~(18)~~ (17)	~~(33)~~ (32)	~~(33)~~ (32)	~~(41,531)~~
2011	~~(3,123)~~ (3,117)	~~(42,312)~~ (42,279)	~~(1,236)~~ (1,227)	~~(22)~~ (22)	~~(5)~~ (4)	~~(18)~~ (17)	~~(50,176)~~
2012	~~(4,453)~~	~~(49,381)~~	~~(1,947)~~	~~(340)~~	~~33.7~~	~~21.30~~	~~(154,576)~~
	(3,251)	(42,013)	(1,226)	(22)	19.6	7.24	
2014	~~(4,821)~~	~~(49,551)~~	~~(1,998)~~	~~(340)~~	~~1.2~~	~~0.75~~	~~(155,966)~~
	(4,453)	(49,381)	(1,947)	(340)	33.7	21.30	
2015	(4,821)	(49,551)	(1,998)	(340)	1.2	0.75	

Microturbines/LNG - Total Compared to Baseline

Description	NOx, lb/day	CO, lb/day	VOC, lb/day	SOx, lb/day	PM10, lb/day	PM2.5 lb/day	~~CO_2, ton/year~~
2008	~~(106)~~ (100)	~~(334)~~ (301)	~~(22)~~ (14)	~~(7.5)~~ (6.9)	~~(0.1)~~ 0.8	~~0.4~~ 0.4	~~(22,186)~~
2009	~~(3,231)~~ (3,225)	~~(38,425)~~ (38,392)	~~(1,226)~~ (1,217)	~~(18)~~ (17)	~~(33)~~ (32)	~~(33)~~ (32)	~~(41,531)~~
2010	~~(3,231)~~ (3,225)	~~(38,425)~~ (38,392)	~~(1,226)~~ (1,217)	~~(18)~~ (17)	~~(33)~~ (32)	~~(33)~~ (32)	~~(41,531)~~
2011	~~(3,123)~~ (3,117)	~~(42,312)~~ (42,279)	~~(1,236)~~ (1,227)	~~(22)~~ (22)	~~(5)~~ (4)	~~(18)~~ (17)	~~(50,176)~~
2012	~~(4,837)~~	~~(49,846)~~	~~(1,901)~~	~~(340)~~	~~(72)~~	~~(84)~~	~~(154,468)~~
	(3,232)	(41,963)	(1,220)	(22)	22	10	
2014	~~(5,205)~~	~~(50,016)~~	~~(1,952)~~	~~(340)~~	~~(104)~~	~~(104)~~	~~(155,857)~~
	(4,989)	(50,536)	(2,009)	(477)	(141)	(153)	
2015	(5,358)	(50,706)	(2,060)	(477)	(173)	(174)	

Table C-90
Estimation of the Number of Electric Motor Replacements of Non-Biogas Engines Required for Alternative D to Be Carbon Neutral

SCR - Carbon Neutral Calculation

Description	Proposed Project CO2, ton/year	No Electrification CO2, ton/year	Reduction in CO2 from Electrification	Average CO2 Savings per Motor	Average No of Motor to Stay Carbon Neutral
Baseline					
2008	(22,186)	(22,186)	0		
2009	(41,531)	(22,713)	18,819		
2010	(41,531)	(22,713)	18,819		
2011	(52,139)	(21,001)	31,138		
2012	(16,178)	14,203	30,381		
2014	(16,224)	14,157	30,381		
2013-2018	(97,344)	84,943	182,287		
10 year total	(248,723)	32,719	281,443	1,665	20

Gas Turbines – Carbon Neutral Calculation

Description	Proposed Project CO2, ton/year	No Electrification CO2, ton/year	Reduction in CO2 from Electrification	Average CO2 Savings per Motor	Average No of Motor to Stay Carbon Neutral
Baseline					
2008	(22,186)	(22,186)	0		
2009	121,080	(22,713)	18,819		
2010	(41,531)	(22,713)	18,819		
2011	(52,070)	(20,932)	31,138		
2012	(18,173)	12,208	30,381		
2014	(18,246)	12,135	30,381		
2013-2018	(109,474)	72,813	182,287		
10 year total	(100,168)	18,664	118,831	703	27

Table C-90 (Continued)
Estimation of the Number of Electric Motor Replacements of Non-Biogas Engines Required for Alternative D to Be Carbon Neutral

Microturbines - Carbon Neutral Calculation

Description	Proposed Project CO2, ton/year	No Electrification CO2, ton/year	Reduction in CO2 from Electrification	Average CO2 Savings per Motor	Average No of Motor to Stay Carbon Neutral
Baseline					
2008	(22,186)	(22,186)	0		
2009	(41,531)	(22,713)	18,819		
2010	(41,531)	(22,713)	18,819		
2011	(52,070)	(20,932)	31,138		
2012	(18,059)	12,322	30,381		
2014	(18,132)	12,249	30,381		
2013-2018	(108,790)	73,497	182,287		
10 year total	(261,981)	19,462	281,443	1,665	12

Gas Turbines/LNG - Carbon Neutral Calculation

Description	Proposed Project CO2, ton/year	No Electrification CO2, ton/year	Reduction in CO2 from Electrification	Average CO2 Savings per Motor	Average No of Motor to Stay Carbon Neutral
Baseline					
2008	(22,186)	(22,186)	0		
2009	(41,531)	(22,713)	18,819		
2010	(41,531)	(22,713)	18,819		
2011	(50,176)	(19,038)	31,138		
2012	(154,576)	(124,195)	30,381		
2014	(155,966)	(125,585)	30,381		
2013-2018	(935,795)	(753,508)	182,287		
10 year total	(1,223,610)	(942,167)	281,443	1,665	0

Table C-90 (Concluded)
Estimation of the Number of Electric Motor Replacements of Non-Biogas Engines Required for Alternative D to Be Carbon Neutral

Microturbines/LNG - Carbon Neutral Calculation

Description	Proposed Project CO2, ton/year	No Electrification CO2, ton/year	Reduction in CO2 from Electrification	Average CO2 Savings per Motor	Average No of Motor to Stay Carbon Neutral
Baseline					
2008	(22,186)	(22,186)	0		
2009	(41,531)	(22,713)	18,819		
2010	(41,531)	(22,713)	18,819		
2011	(50,176)	(19,038)	31,138		
2012	(154,468)	(124,087)	30,381		
2014	(155,857)	(125,476)	30,381		
2013-2018	(935,145)	(752,858)	182,287		
10 year total	(1,222,851)	(941,408)	281,443	1,665	0

Table C-91
Summary of the Number of Electric Motor Replacements of Non-Biogas Engines Required for Alternative D to Be Carbon Neutral

Description	Proposed Project CO2, ton/year	No Electrification CO2, ton/year	Reduction in CO2 from Electrification	Average CO2 Savings per Motor	Average No of Motor to Stay Carbon Neutral
SCR	(248,723)	32,719	281,443	1,665	20
Replace ICE with Gas Turbine	(100,168)	18,664	118,831	703	27
Replace ICE Microturbine	(261,981)	19,462	281,443	1,665	12
Replace LFG w LNG, DG w Turbines	(1,223,610)	(942,167)	281,443	1,665	0
Replace LFG w LNG, DG w Microturbines	(1,222,851)	(941,408)	281,443	1,665	0

Table C-92
Summary of Alternative D Energy Effects Compared to Baseline

Description	Natural Gas Consumption, MMBtu/yr	Electricity Consumption, MWH/yr	Shaft Work Produced, Hp-Hrs/yr	Diesel Fuel Consumption, gal/yr	LNG Production, MMBtu/yr
SCR	(547,111)	174,100	(59,006)	31,152	
Gas Turbines	(476,752)	229,556	(15,123,937)	38,128	
Micro Turbines	(431,194)	273,408	(15,123,937)	41,241	
Gas Turbines/LNG	(204,108)	558,557	(15,123,937)	38,128	2,374,019
Microturbines/LNG	(184,431)	576,527	(15,123,937)	57,364	2,374,019

Table C-93
Exception for ICEs That Heat Digester Gas Calculations for Proposed Project, Alternative B and Alternative D

Assumptions

- Two 574 bhp engines and one stand-by engine
- 2006 fuel use:
  - 5.34×10^{10} Btu/year of digester gas
  - 2.24×10^{10} Btu/year of natural gas

  Therefore, 7.52×10^{10} Btu/year (8.65 MMBtu/hour) total fuel use
- 35 percent heat recovery by boiler
- 31 percent engine efficiency
- 80 percent boiler efficiency
- Engine CO and VOC emission factors are based on source test.
- Engine SOx emission factor is based on 1 grain sulfur per 1000 std cubic feet natural gas (PUC maximum allowable).
- Engine PM10 emission factor from AP-42.
- Boiler CO emission factors based on 50 ppm at three percent oxygen (typical for a firetube boiler).
- Boiler VOC and PM emission factors are from AP-42.

Estimated Full Load Fuel Use
(574 bhp x 2,545)/(0.31 engine efficiency) = 4.71 MMBtu/hour

Average Load
(8.65 MMBtu/hour)/(2 engines x 4.71 MMBtu/hour) = 91.8 percent

Estimated Heat Recovery
8.65 MMBtu/hour x 0.35 heat recovery = 3.0 MMBtu/hour

Fuel Use with 10 Percent Natural Gas
(5.34×10^{10} Btu/year x 10/9)/(8,760 hour/year) = 6.77 MMBtu/hour ~ 72 percent load

Estimated Heat Recovery
6.77 MMBtu/hour x 0.35 heat recovery = 2.37 MMBtu/hour

Reduced Heat Recovery
3.0 MMBtu/hour – 2.37 MMBtu/hour = 0.63 MMBtu/hour

Stand-by Boiler Size:
(0.63 MMBtu/hour)/(0.80 boiler efficiency) = 0.79 MMBtu/hour

Reduced Engine Fuel Use
8.65 MMBtu/hour - 6.77 MMBtu/hour = 1.88 MMBtu/hr

Annual ICE Emissions from Using More Than 10 Percent Natural Gas
1.88 MMBtu/hour x 720 hour/year x 0.12 lb NOx/MMBtu = 162 lb NOx /year
1.88 MMBtu/hour x 720 hour/year x 0.728 lb CO/MMBtu = 985 lb CO/year
1.88 MMBtu/hour x 720 hour/year x 0.196 lb VOC/MMBtu = 265 lb VOC/year
1.88 MMBtu/hour x 720hour/year x 0.0134 lb SOx/MMBtu = 18.1 lb SOx/year
1.88 MMBtu/hour x 720 hour/year x 0.0194 lb PM10/MMBtu = 26.3 lb PM10/year
26.3 lb PM/year x 0.998 lb PM2.5/lb PM10 = 26.2 lb PM2.5/year
1.88 MMBtu/hour x 720 hour/year x 115 lb CO2/MMBtu = 155,664 lb CO2/year

Daily ICE Emissions from Using More Than 10 Percent Natural Gas
1.88 MMBtu/hour x 24 hour/day x 0.12 lb NOx/MMBtu = 5.4 lb NOx /day
1.88 MMBtu/hour x 24 hour/day x 0.728 lb CO/MMBtu = 32.8 lb CO/day
1.88 MMBtu/hour x 24 hour/day x 0.196 lb VOC/MMBtu = 8.8 lb VOC/day
1.88 MMBtu/hour x 720hour/day x 0.0134 lb SOx/MMBtu = 0.60 lb SOx/day
1.88 MMBtu/hour x 24 hour/day x 0.0194 lb PM10/MMBtu = 0.88 lb PM10/day
26.3 lb PM/day x 0.998 lb PM2.5/lb PM10 = 0.88 lb PM2.5/day

Summary of Exception for Natural Gas for ICEs That Heat Digester Gas

Description	**NOx Emissions, lb/day**	**CO Emissions, lb/day**	**VOC Emissions, lb/day**	**SOx Emissions, lb/day**	**PM10 Emissions, lb/day**	**PM2.5 Emissions, lb/day**
ICE	5.41	32.85	8.8	0.6	0.88	0.87

Proposed Project

Description	**NOx Emissions, lb/day**	**CO Emissions, lb/day**	**VOC Emissions, lb/day**	**SOx Emissions, lb/day**	**PM10 Emissions, lb/day**	**PM2.5 Emissions, lb/day**
ICE Exception	5.4	32.8	8.8	0.60	0.88	0.87
Significance Threshold	55	550	75	150	150	55
Significant or Substantial Increase?	No	No	No	No	No	No

Alternative B

Description	**NOx Emissions, lb/day**	**CO Emissions, lb/day**	**VOC Emissions, lb/day**	**SOx Emissions, lb/day**	**PM10 Emissions, lb/day**	**PM2.5 Emissions, lb/day**
ICE Exception	5.4	32.8	8.8	0.60	0.88	0.87
Significance Threshold	55	550	75	150	150	55
Significant or Substantial Increase?	No	No	No	No	No	No

Alternative D

Description	**NOx Emissions, lb/day**	**CO Emissions, lb/day**	**VOC Emissions, lb/day**	**SOx Emissions, lb/day**	**PM10 Emissions, lb/day**	**PM2.5 Emissions, lb/day**
Worst-Case						
ICE Exception	5.41	32.85	8.84	0.60	0.88	0.87
Significance Threshold	55	550	75	150	150	55
Significant or Substantial Increase?	No	No	No	No	No	No

Table C-93
Exception for ICEs That Heat Digester Gas Calculations for Alternative C

Assumptions

- Two 574 bhp engines and one stand-by engine
- 2006 fuel use:
  - 5.34×10^{10} Btu/year of digester gas
  - 2.24×10^{10} Btu/year of natural gas

  Therefore, 7.52×10^{10} Btu/year (8.65 MMBtu/hour) total fuel use
- 35 percent heat recovery by boiler
- 31 percent engine efficiency
- 80 percent boiler efficiency
- Engine CO and VOC emission factors are based on source test.
- Engine SOx emission factor is based on 1 grain sulfur per 1000 std cubic feet natural gas (PUC maximum allowable).
- Engine PM10 emission factor from AP-42.
- Boiler CO emission factors based on 50 ppm at three percent oxygen (typical for a firetube boiler).
- Boiler VOC and PM emission factors are from AP-42.

Estimated Full Load Fuel Use

(574 bhp x 2,545)/(0.31 engine efficiency) = 4.71 MMBtu/hour

Average Load

(8.65 MMBtu/hour)/(2 engines x 4.71 MMBtu/hour) = 91.8 percent

Estimated Heat Recovery

8.65 MMBtu/hour x 0.35 heat recovery = 3.0 MMBtu/hour

Fuel Use with 10 Percent Natural Gas
(5.34×10^{10} Btu/year x 10/9)/(8,760 hour/year) = 6.77 MMBtu/hour ~ 72 percent load

Estimated Heat Recovery
6.77 MMBtu/hour x 0.35 heat recovery = 2.37 MMBtu/hour

Reduced Heat Recovery
3.0 MMBtu/hour – 2.37 MMBtu/hour = 0.63 MMBtu/hour

Stand-by Boiler Size:
(0.63 MMBtu/hour)/(0.80 boiler efficiency) = 0.79 MMBtu/hour

Reduced Engine Fuel Use
8.65 MMBtu/hour - 6.77 MMBtu/hour = 1.88 MMBtu/hr

Annual ICE Emissions from Using More Than 25 Percent Natural Gas
1.03 MMBtu/hour x 720 hour/year x 0.12 lb NOx/MMBtu = 89 lb NOx /year
1.03 MMBtu/hour x 720 hour/year x 0.728 lb CO/MMBtu = 540 lb CO/year
1.03 MMBtu/hour x 720 hour/year x 0.196 lb VOC/MMBtu = 145 lb VOC/year
1.03 MMBtu/hour x 720hour/year x 0.0134 lb SOx/MMBtu = 9.9 lb SOx/year
1.03 MMBtu/hour x 720 hour/year x 0.0194 lb PM10/MMBtu = 14.4 lb PM10/year
14.4 lb PM/year x 0.998 lb PM2.5/lb PM10 = 14.4 lb PM2.5/year
1.03 MMBtu/hour x 720 hour/year x 115 lb CO2/MMBtu = 85,295 lb CO2/year

Daily ICE Emissions from Using More Than 25 Percent Natural Gas
1.03 MMBtu/hour x 24 hour/day x 0.12 lb NOx/MMBtu = 3.0 lb NOx /day
1.03 MMBtu/hour x 24 hour/day x 0.728 lb CO/MMBtu = 18.0 lb CO/day
1.03 MMBtu/hour x 24 hour/day x 0.196 lb VOC/MMBtu = 4.8 lb VOC/day
1.03 MMBtu/hour x 720hour/day x 0.0134 lb SOx/MMBtu = 0.33 lb SOx/day
0.33 MMBtu/hour x 24 hour/day x 0.0194 lb PM10/MMBtu = 0.48 lb PM10/day
26.3 lb PM/day x 0.998 lb PM2.5/lb PM10 = 0.48 lb PM2.5/day

Summary of Exception for Natural Gas for ICEs That Heat Digester Gas

Description	**NOx Emissions, lb/day**	**CO Emissions, lb/day**	**VOC Emissions, lb/day**	**SOx Emissions, lb/day**	**PM10 Emissions, lb/day**	**PM2.5 Emissions, lb/day**
ICE	3.0	18.0	4.8	0.39	0.48	0.48

Alternative C

Description	**NOx Emissions, lb/day**	**CO Emissions, lb/day**	**VOC Emissions, lb/day**	**SOx Emissions, lb/day**	**PM10 Emissions, lb/day**	**PM2.5 Emissions, lb/day**
ICE Exception	3.0	18.0	4.8	0.39	0.48	0.48
Significance Threshold	55	550	75	150	150	55
Significant or Substantial Increase?	No	No	No	No	No	No

APPENDIX D (of the ~~Draft~~Final EA)

NOTICE OF PREPARATION AND INITIAL STUDY

South Coast
Air Quality Management District
21865 Copley Drive, Diamond Bar, CA 91765-4182
(909) 396-2000 • http://www.aqmd.gov

SUBJECT: **NOTICE OF PREPARATION OF A DRAFT ENVIRONMENTAL ASSESSMENT**

PROJECT TITLE: **PROPOSED AMENDED RULE 1110.2 – EMISSIONS FROM GASEOUS- AND LIQUID-FUELED INTERNAL COMBUSTION ENGINES (ICES)**

In accordance with the California Environmental Quality Act (CEQA), the South Coast Air Quality Management District (SCAQMD), as the Lead Agency, has prepared this Notice of Preparation (NOP) and Initial Study (IS). This NOP serves two purposes: 1) to solicit information on the scope of the environmental analysis for the proposed project, and 2) to notify the public that the SCAQMD will prepare a Draft Environmental Assessment (EA) to further assess potential environmental impacts that may result from implementing the proposed project.

This letter, NOP and the attached IS are not SCAQMD applications or forms requiring a response from you. Their purpose is simply to provide information to you on the above project. If the proposed project has no bearing on you or your organization, no action on your part is necessary.

The SCAQMD has also prepared an Initial Study (IS) for the proposed project, which includes a project description and an environmental checklist. The IS and other relevant documents may be obtained by calling the SCAQMD Public Information Center at (909) 396-2039 or by accessing the SCAQMD's CEQA website at http://www.aqmd.gov/ceqa/aqmd.html. Comments can also be sent via facsimile to (909) 396-3324 or e-mail at jkoizumi@aqmd.gov. Mr. Koizumi can be reached by calling (909) 396-3234. Comments must be received no later than 5:00 PM on May 25, 2007. Please include the name and phone number of the contact person for your agency. Questions regarding the proposed rule language should be directed to Mr. Martin Kay at (909) 396-3115.

A Public Workshop for the proposed amended rule was held February 6, 2007. The Public Hearing for the proposed project is scheduled for September 7, 2007. (Note: This public meeting date is subject to change.)

Date: April 20, 2007

Signature: Steve Smith

Steve Smith, Ph.D.

Title: Program Supervisor

Telephone: (909) 396-3054

Reference: California Code of Regulations, Title 14, §§15082(a), 15103, and 15375

SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT
21865 Copley Drive, Diamond Bar, CA 91765-4182

NOTICE OF PREPARATION OF A DRAFT ENVIRONMENTAL ASSESSMENT

Project Title:
Initial Study (IS) for Proposed Amended Rule (PAR) 1110.2 – Emissions from Gaseous- and Liquid-Fueled Internal Combustion Engines (ICEs)

Project Location:
South Coast Air Quality Management District: the four-county South Coast Air Basin (Orange County and the non-desert portions of Los Angeles, Riverside and San Bernardino counties) and the Riverside County portions of the Salton Sea Air Basin and the Mojave Desert Air Basin.

Description of Nature, Purpose, and Beneficiaries of Project:
The purpose of PAR 1110.2 is to reduce oxides of nitrogen (NOx), volatile organic compounds (VOCs) and carbon monoxide (CO) emissions from gaseous and liquid-fueled ICEs. The proposed amendments would affect stationary, non-emergency engines and would increase monitoring requirements; require engines to meet emission standards equivalent to Best Available Control Technology (BACT); require new electrical generating engines to meet the same requirements as large central power plants, and clarify portable engine requirements.

Lead Agency:	**Division:**
South Coast Air Quality Management District	Planning, Rule Development and Area Sources

Initial Study and all supporting documentation are available at:	**or by calling:**	**Initial Study is available online by accessing the SCAQMD's website at:**
SCAQMD Headquarters 21865 Copley Drive Diamond Bar, CA 91765	(909) 396-2039	http://www.aqmd.gov/ceqa/aqmd.html

The Public Notice of Preparation is provided through the following:
☑ Los Angeles Times (April 26, 2007) ☑ SCAQMD Website ☑ SCAQMD Mailing List

Initial Study Review Period (30-day):
April 26, 2007 – May 25, 2007

Scheduled Public Meeting Dates (subject to change):
SCAQMD Governing Board Hearing: September 7, 2007, 9:00 a.m.; SCAQMD Headquarters

CEQA Scoping Meeting:
February 6, 2007, 10:00 am; SCAQMD Headquarters

Send CEQA Comments to:	**Phone:**	**Email:**	**Fax:**
Mr. James Koizumi	(909) 396-3234	jkoizumi@aqmd.gov	(909) 396-3324

Direct Questions on the Rules:	**Phone:**	**Email:**	**Fax Number:**
Mr. Martin Kay	(909) 396-3115	mkay@aqmd.gov	(909) 396-3252

SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT

Initial Study for:

Proposed Rule 1110.2 – Emissions from Gaseous- and Liquid-Fueled Internal Combustion Engines

April 2007

SCAQMD No. 280307JK

Executive Officer
Barry R. Wallerstein, D. Env.

Deputy Executive Officer
Planning, Rule Development and Area Sources
Elaine Chang, DrPH

Assistant Deputy Executive Officer
Planning, Rules, and Area Sources
Laki Tisopulos, Ph.D., P.E.

Planning and Rules Manager
Planning, Rule Development and Area Sources
Susan Nakamura

Author:	James Koizumi	Air Quality Specialist
Technical Assistance:	Alfonso Baez, M.S,	Senior Air Quality Engineer
	Howard Lange, Ph.D.	Air Quality Engineer II
Reviewed By:	Marty Kay, P.E., M.S.,	Program Supervisor, Planning, Rules, and Area Sources
	Mike Harris	Senior Deputy District Counsel

SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT
GOVERNING BOARD

CHAIRMAN:	WILLIAM A. BURKE, Ed.D. Speaker of the Assembly Appointee
VICE CHAIRMAN:	S. ROY WILSON, Ed.D. Supervisor, Fourth District Riverside County Representative

MEMBERS:

MICHAEL D. ANTONOVICH
Supervisor, Fifth District
Los Angeles County Representative

BILL CAMPBELL
Supervisor, Third District
County of Orange

JANE W. CARNEY
Senate Rules Committee Appointee

RONALD O. LOVERIDGE
Mayor, City of Riverside
Cities Representative, Riverside County

GARY OVITT
Supervisor, Fourth District
San Bernardino County Representative

JAN PERRY
Councilmember, Ninth District
Cities Representative, Los Angeles County, Western Region

MIGUEL A. PULIDO
Mayor, City of Santa Ana
Cities Representative, Orange County

TONIA REYES URANGA
Councilmember, City of Long Beach
Cities Representative, Los Angeles County, Eastern Region

DENNIS YATES
Mayor, Chino
Cities Representative, San Bernardino County

Vacant
Governor’s Appointee

EXECUTIVE OFFICER:
BARRY R. WALLERSTEIN, D.Env.

TABLE OF CONTENTS

TABLE OF CONTENTS (CONTINUED)

Table of Acronyms and Abbreviations

Acronym/Abbreviation	Description
ACWA	Association of California Water Agencies
AFRC	Air-to-fuel ratio controller
AQMP	Air quality management plan
ASME	American Society Of Mechanical Engineers
ATCM	Airborne Toxic Control Measures
BACT	Best Available Control Technology
BARCT	Best available retrofit control technology
bph	Brake horsepower
BTU	British thermal unit
CARB	California Air Resources Board
Catox	Catalytic oxidation
CEMS	Continuous emission monitoring system
CEQA	California Environmental Quality Act
CI	Compression-ignition
CNG	Compressed natural gas
CO	Carbon monoxide
dBA	Decibels
EA	Environmental Assessment
EEF	electrical energy factor
EGR	Exhaust gas recirculation
ERPG	Emergency Response Planning Guideline
FY	Fiscal year
g	Gram
HHV	High heating value
I&M	Inspection and monitoring
ICE	Internal combustion engine
in	Inches
IS	Initial Study
k	Kilo
kW	Kilowatt
L	Concentration limit
LA DWP	Los Angeles Department of Water and Power
lb	Pound
LPG	liquefied petroleum gas
m	Meter
MDAB	Mojave Desert Air Basin
μg	Micrograms

Table of Acronyms and Abbreviations (continued)

Acronym/Abbreviation	Description
MM	Million
MMBtu	Million British thermal units
MMSCF	Million standard cubic feet
MTA	Los Angeles Metropolitan Transportation Agency
MWD	Metropolitan Water District
MW_e	Electrical megawatt-hours
MW_{th}-hours	Thermal megawatt-hours
NG	natural gas
NMHC	Non-methane hydrocarbon
NOx	Oxides of nitrogen
NSCR	Non-selective catalytic reduction
NSPS	New Source Performance Standards
O2	Oxygen
OSHA	Occupational Safety and Health Administration
Ox Cat	Catalytic oxidation
PAR	Proposed amended rule
PERP	Portable Equipment Registration Program
PM	Particulate matter
PM10	Particulate matter less than 10 microns in diameter
PM2.5	Particulate matter less than 2.5microns in diameter
ppm	Parts per million
ppmdv	Parts per million, dry volume
ppmv	Parts per million by volume
PSC	Pre-stratified charge
R	Ratio
RACT	Retrofit available control technology
RECLAIM	Regional CLean Air Incentives Market
RICE	Reciprocating Internal Combustion Engines
ROG	Reactive organic gas
SCAB	South Coast Air Basin
SCAQMD	South Coast Air Quality Management District
scf	Standard cubic feet
SCR	Selective catalytic reduction
SI	Spark-ignited
SSAB	Salton Sea Air Basin
TAC	Toxic Air Contaminant
TWC	Three-way catalyst

Table of Acronyms and Abbreviations (continued)

Acronym/Abbreviation	Description
VOC	Volatile organic compound
W	Watt
WD	Water District
wt	Weight

CHAPTER 1 - PROJECT DESCRIPTION

INTRODUCTION

The California Legislature created the South Coast Air Quality Management District (SCAQMD) in 1977[1] as the agency responsible for developing and enforcing air pollution control rules and regulations in the South Coast Air Basin (Basin) and portions of the Salton Sea Air Basin and Mojave Desert Air Basin referred to herein as the district. By statute, the SCAQMD is required to adopt an air quality management plan (AQMP) demonstrating compliance with all federal and state ambient air quality standards for the district[2]. Furthermore, the SCAQMD must adopt rules and regulations that carry out the AQMP[3]. The 2003 AQMP concluded that major reductions in emissions of volatile organic compounds (VOCs) and oxides of nitrogen (NOx) are necessary to attain the air quality standards for ozone and particulate matter (PM10 and PM2.5).

Rule 1110.2 was adopted in August 1990 to control NOx, carbon monoxide (CO), and VOC from gaseous and liquid-fueled internal combustion engines (ICEs). For all stationary and portable engines over 50 brake horsepower (bhp), it required that either 1) NOx emissions be reduced over 90 percent to one of two compliance limits specified by the rule, or; 2) the engines be permanently removed from service or replaced with electric motors. It was amended in September 1990 to clarify rule language. It was then amended in August and December of 1994 to modify the CO monitoring requirements and to clarify rule language. The amendment of November 1997 eliminated the requirement for continuous monitoring of CO, reduced the source testing requirement from once every year to once every three years, and exempted nonroad engines, including portable engines, from most requirements. The last amendment in June 2005 made the previously exempt agricultural engines subject to the rule.

The objective of proposed amended rule (PAR) 1110.2 is to reduce NOx, VOC and CO emissions from gaseous and liquid-fueled ICE. PAR 1110.2 would partially implement the 2007 AQMP Control Measure MCS-01 – Facility Modernization, which requires facilities to retrofit or replace their equipment to achieve Best Available Control Technology (BACT); emission levels. The proposed amendments would affect stationary, non-emergency engines and would increase monitoring requirements; require to meet emission standards equivalent to BACT; require new electrical generating engines to meet the same requirements as large central power plants, and clarify portable engine requirements. The proposed project would also remove obsolete portable engine requirements from the existing rule.

This Initial Study (IS), prepared pursuant to the California Environmental Quality Act (CEQA), identifies only aesthetics and operational related air pollutant emissions as a potentially significant adverse impact from implementing the proposed project. A Draft Environmental Assessment (EA) will be prepared to analyze whether the potential hazard and hazardous impacts are significant. Any other potentially significant environmental impacts identified through this Notice of Preparation/Initial Study process will also be evaluated and may be considered for further analysis in the Draft EA.

---

[1] The Lewis-Presley Air Quality Management Act, 1976 Cal. Stats., ch 324 (codified at Health & Safety Code, §§40400-40540).

[2] Health & Safety Code, §40460 (a).

[3] Health & Safety Code, §40440 (a).

Throughout this document, references to the proposed project or PAR 1110.2 are used interchangeably.

CALIFORNIA ENVIRONMENTAL QUALITY ACT

PAR 1110.2 is a "project" as defined by the CEQA. CEQA requires that the potential adverse environmental impacts of proposed projects be evaluated and that methods to reduce or avoid identified significant adverse environmental impacts of these projects be implemented if feasible. The purpose of the CEQA process is to inform the SCAQMD's Governing Board, public agencies, and interested parties of potential adverse environmental impacts that could result from implementing the proposed project and to identify feasible mitigation measures when an impact is significant.

California Public Resources Code §21080.5 allows public agencies with regulatory programs to prepare a plan or other written documents in lieu of an environmental impact report once the Secretary of the Resources Agency has certified the regulatory program. The SCAQMD's regulatory program was certified by the Secretary of Resources Agency on March 1, 1989 and is codified as SCAQMD Rule 110. Pursuant to Rule 110 (the rule which implements the SCAQMD's certified regulatory program), SCAQMD is preparing a Draft Environmental Assessment (EA) to evaluate potential adverse impacts from PAR 1110.2.

The SCAQMD as Lead Agency for the proposed project has prepared this IS (which includes an Environmental Checklist). The Environmental Checklist provides a standard evaluation tool to identify a project's adverse environmental impacts. The Initial Study is also intended to provide information about the proposed project to other public agencies and interested parties prior to the release of the Draft EA. Written comments on the scope of the environmental analysis and possible project alternatives received by the SCAQMD during the 30-day review and comment period will be considered when preparing the Draft EA.

PROJECT LOCATION

The SCAQMD has jurisdiction over an area of 10,473 square miles (referred to hereafter as the district), consisting of the four-county South Coast Air Basin (Basin) and the Riverside County portions of the Salton Sea Air Basin (SSAB) and the Mojave Desert Air Basin (MDAB). The Basin, which is a subarea of the SCAQMD's jurisdiction, is bounded by the Pacific Ocean to the west and the San Gabriel, San Bernardino, and San Jacinto Mountains to the north and east. The 6,745 square-mile Basin includes all of Orange County and the nondesert portions of Los Angeles, Riverside, and San Bernardino counties. The Riverside County portion of the SSAB and MDAB is bounded by the San Jacinto Mountains in the west and spans eastward up to the Palo Verde Valley. The federal nonattainment area (known as the Coachella Valley Planning Area) is a subregion of both Riverside County and the SSAB and is bounded by the San Jacinto Mountains to the west and the eastern boundary of the Coachella Valley to the east (Figure 1-1).

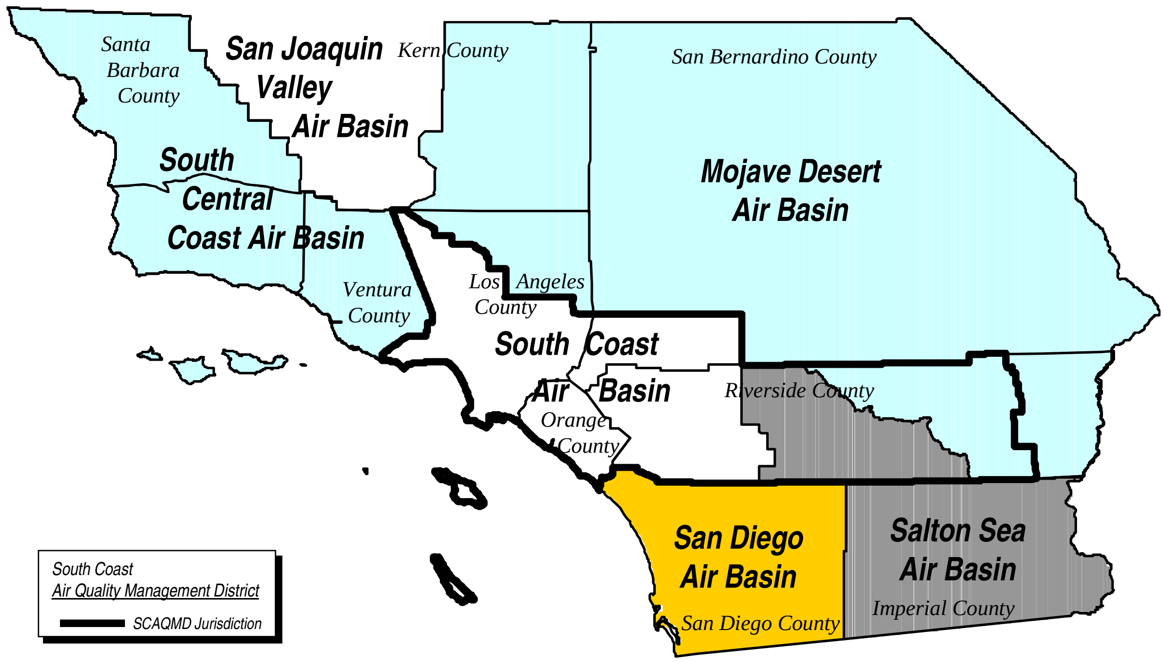


Figure 1-1
South Coast Air Quality Management District

PROJECT OBJECTIVES

The objective of the project is to partially implement 2007 AQMP Control Measure MSC–01 – Facility Modernization, which requires facilities not participating in the NOx Regional CLean Air Incentives Market (RECLAIM) Program to retrofit or replace existing equipment with NOx BACT at the end of a predetermined life span. PAR 1110.2 would also increase engine compliance by better monitoring, recordkeeping and reporting. PAR 1110.2 would implement SB 1298 distributed generation emission standards for new electrical generating engines, as well as, address issues EPA has with the current Rule 1110.2.

The purpose of the proposed amendments are to: 1) improve the compliance record of engines with better monitoring, recordkeeping and reporting; and 2) achieve further emission reduction based on the cleanest available technologies.

PROJECT DESCRIPTION

A summary of the proposed amendments follows:

Applicability

PAR 1110.2 applies to all stationary and portable engines over 50 rated bhp.

Definitions

This subdivision lists keywords related to gaseous- and liquid fueled engines and defines them for clarity and to enhance enforceability. A new definition for "oxides of nitrogen" and revised definition of "approved emission control plan" are proposed to simply clarify the intent of the rule. New definitions for "net electrical energy", "rich-burn engine with a three-way catalyst", and "useful heat recovered" were developed to support the new requirements previously discussed.

Requirements

Operators of affected operations would be required to comply with the following requirements by September 7, 2007 unless otherwise stated.

Stationary Engines

Reduction of the Emission Concentration Limits

Subparagraph (d)(1)(B) currently limits NOx, VOC and CO concentrations to produced by non-biogas (landfill or digestor gas)-fired engines 36, 250 and 2000 parts per million, dry volume (ppmvd) respectively. The proposed amendments will reduce these limits by 2010 or 2011 to levels comparable to current BACT.

Table 1-1
Proposed Concentration Limits

CONCENTRATION LIMITS FOR NON- BIOGAS-FIRED ENGINES		
NO_x (ppm)[1]	VOC (ppm)[2]	CO (ppm)[1]
bhp ≥ 500: 36 bhp < 500: 45	250	2000
CONCENTRATION LIMITS EFFECTIVE JULY 1, 2010		
NO_x (ppm)[1]	VOC (ppm)[2]	CO (ppm)[1]
bhp ≥ 500: 11 bhp < 500: 45	bhp ≥ 500: 30 bhp < 500: 250	bhp ≥ 500: 70 bhp < 500: 2000
CONCENTRATION LIMITS EFFECTIVE JULY 1, 2011		
NO_x (ppm)[1]	VOC (ppm)[2]	CO (ppm)[1]
11	30	70

1 Corrected to 15 percent oxygen on a dry basis and averaged over 15 minutes.
2 Measured as carbon, corrected to 15 percent oxygen on a dry basis and averaged over 30 minutes.

Revisions to the Efficiency Correction for Stationary Engines

The current rule in subparagraph (d)(1)(C) allows most stationary engines to upwardly adjust the NOx and VOC ppmvd emission limits in Table III based on the actual engine efficiency or the manufacturer's rated efficiency. More efficient engines are allowed higher ppmvd limits.

The proposed amended subparagraph (d)(1)(C) limits the efficiency correction to biogas-fired engines, requires that the correction be based on actual efficiency from (American Society Of Mechanical Engineers) ASME test procedures, requires the engines to use at least 90 percent biogas on an annual basis, and requires the corrected emission limits to be stated on the operating permit.

Emission Standards for Biogas Engines
In addition to allowing biogas engines to continue to use an efficiency correction factor, the following emission concentration limits are proposed for biogas-fired engines:

Table 1-2
Proposed Concentration Limits for Biogas Engines

Concentration Limits For Biogas Gas-Fired Engines		
NO_x (ppm)[1]	VOC (ppm)[2]	CO (ppm)[1]
bhp ≥ 500: 36 x ECF[3] bhp < 500: 45 x ECF[3]	Landfill Gas: 40 Digestor Gas: 250 x ECF[3]	2000
Concentration Limits Effective July 1, 2012		
NO_x (ppm)[1]	VOC (ppm)[2]	CO (ppm)[1]
11	30	70

1 Corrected to 15 percent oxygen on a dry basis and averaged over 15 minutes.
2 Measured as carbon, corrected to 15 percent oxygen on a dry basis and averaged over 30 minutes.
3 ECF is the efficiency correction factor.

Initially, only the VOC limit for landfill gas-fired engines would change, to be consistent with other current requirements. In 2012, the emissions limits would drop to BACT levels, just as is proposed for other engines.

Air-to-Fuel Ratio Controllers
The current rule doesn't require an air-to-fuel ratio controller for ICEs. The proposed amendments require ICEs without a CEMS to install an air-to-fuel ratio controller (AFRC) with an oxygen sensor and feedback control.

Emission Standards for New Non-Emergency Electrical Generation Engines
New non-emergency electrical generation engines are proposed in subparagraph (d)(1)(F) to be subject to the emission standards in the following table.

Table 1-3
Proposed Emission Limits for New Electrical Generation Engines

Emission Standards for New Electrical Generation Engines	
Pollutant	**Emission Standard (lbs/MW-hr)**
NOx	0.07
CO	0.10
VOC	0.02

These emission standards do not apply to biogas-fired engines or engines installed or issued a permit to construct before September 7, 2007.

For engines that do not produce combined heat and power (CHP), the emission standards are based on the net electrical megawatt-hours (MW_e-hours) produced. CHP (also know as cogeneration) engines may also take credit for the thermal megawatt-hours (MW_{th}-hours) of useful heat produced, with one MW_{th}-hour for each 3.4 million British thermal units (Btus). The thermal energy could take the form of hot water, steam or other medium.

For CHP engines, the operator will choose short-term emission limits in pounds per MW_e-hours that the engine must meet at all times. The operator will also choose an annual electrical energy factor (EEF), such that when the short-term emission limit is multiplied by the annual EEF, the result does not exceed the values in the Table 1-3. The EEF is the annual net electrical energy produced divided by the sum of the electrical and thermal energy produced. The operator will have to also meet the annual EEF limit.

Portable Engines

Staff proposes to remove the emission limits and related requirements for portable engines in subparagraph (d)(2)(A) and add a reference to the California Air Resources Board (CARB)-adopted, portable diesel (Airborne Toxic Control Measures) ATCM and the Large Spark-Ignition Fleet Requirements, to which some portable engines are subject.

Compliance

The unnecessary existing paragraphs (e)(1) and (e)(3) are proposed for deletion. New paragraphs (e)(3) through (e)(5) propose compliance schedules for non-agricultural engines required to meet the future emission limits, the stationary engine continuous emission monitoring system (CEMS) requirements, and the inspection and monitoring (I&M) plans. The schedules will allow time for review and approval of applications for permits to construct, CEMS application, and I&M plan applications.

New engines will be required to comply with the new CEMS and I&M requirements when they begin operation.

Monitoring, Testing and Recordkeeping

The primary focus of the proposed amendments in this subdivision is to improve the poor compliance record of stationary engines.

Additional CEMS Requirements

The existing subparagraph (f)(1)(A) requires 1000 bhp engines and larger, that produce two million bhp-hours per year or more to have a NOx CEMS. The proposed amendments, effective on July 1, 2008, add CO emission monitoring back into the rule in subparagraph (f)(1)(A), as it was before the 1997 amendment. In addition, the CEMS requirement will be extended to stationary engines at facilities with multiple engines at the same location (within 75 feet of each other) that have a cumulative stationary engine horsepower rating of 1,000 bhp or more. To reduce the cost, the CEMS can be time-shared between all engines less than 1,000 bhp.

Source Testing for Stationary Engines

The current requirement of subparagraph (f)(1)(C) is that emission testing be done once every three years. The proposed amendments increase the frequency of source testing every two years, or 8,760 operating hours, whichever occurs first.

In addition, the following source testing reforms are proposed:

- Emissions must be tested at for at least 15 minutes at peak load and for at least 30 minutes during normal operation. The source test can no longer at one load under steady state conditions, unless that is the typical duty cycle. In addition NOx and CO must be tested for at least 15 minutes at actual peak load and actual minimum load.
- Pretests to determine if the engine needs repairs will not be allowed.
- The test must be conducted at least 40 operating hours or one week after any engine tuning or maintenance.
- If a test is started and shows non-compliance, it may not be aborted to allow engine tuning or repairs. The test must be completed and reported.
- A source testing contractor approved by SCAQMD must be used.
- A source test protocol must be submitted and approved by the District at least 60 days before the test is conducted. The protocol will also identify the critical parameters that will be measured during the test, as required by the Inspection and Maintenance Plan (discussed later).
- SCAQMD must be notified of the test date.
- The test report must be submitted to SCAQMD within 45 days of the test date. This will assure that noncompliance will be reported.
- The operator must provide source testing facilities including sampling ports in the stack, safe sampling platforms, safe access to sampling platforms, and utilities for test equipment.

Inspection and Monitoring (I&M) Plan for Stationary Engines

An I&M Plan will be added to the rule in subparagraph (f)(1)(D). Except for engines monitored by a CEMS, stationary engine operators will submit to SCAQMD for approval an I&M Plan to assure continued compliance of the engines between source tests. The I&M Plan will include procedures for:

- Establishing acceptable ranges for control equipment parameters and engine operating parameters that source testing or portable analyzer monitoring has shown result in pollutant concentrations within the rule limits. The required parameters include, but are not limited to: engine load; oxygen sensor voltage output or equivalence ratio (AFRC may use either); for rich-burn engines with three-way catalyst systems (TWCs), catalyst inlet and outlet temperatures and the temperature change across the catalyst; and for lean-burn engines with selective catalytic reduction, the reactant flow rate (ammonia or urea).
- Procedures for a diagnosing emission control malfunctions alerting the owner/operator to the malfunction. A malfunction indicator light and audible alarm is required.
- Weekly, or every 150 operating hours, emissions checks by a portable NOx, CO and oxygen (O2) analyzer. The schedule can be reduced to monthly, or every 750 operating hours if three consecutive weekly tests show compliance. If the monthly test is non-compliant or the oxygen sensor is replaced, then weekly tests must be resumed. In order to representative of actual operation, the test will be conducted at least 72 hours after any engine or control system maintenance or tuning. The portable analyzer will be calibrated, maintained and operated in accordance with the manufacturer's specifications and recommendations and the SCAQMD's "Protocol for the Periodic Monitoring of Nitrogen Oxides, Carbon Monoxide, and Oxygen from Sources Subject to South Coast Air Quality Management District Rule 1110.2"

- At least daily recordkeeping of monitoring data and actions required by the plan, including formats of the recordkeeping;
- Preventive and corrective maintenance, and their schedules;
- For rich-burn engines with TWCs, an emission check will be required when an oxygen sensor set point must be readjusted, or within 24 hours after a new oxygen sensor is installed, to establish new set points at minimum, maximum and midpoint loads.
- Reporting noncompliance to the Executive Officer. If an engine owner/operator finds an engine to be operating outside the acceptable range for control equipment parameters, engine operating parameters, engine exhaust NOx, CO, VOC or oxygen concentrations, the owner/operator will: report the noncompliance within one hour in the same manner required by paragraph (b)(1) of Rule 430 – Breakdowns; immediately correct the noncompliance or shut down the engine within 24 hours or the end of an operating cycle, in the same manner as required by subparagraph (b)(3)(iv) of Rule 430; and comply with all requirements of Rule 430 if there was a breakdown.
- Recordkeeping, including formats of the recordkeeping.
- Plan revisions. Before any change in I&M plan operations can be implemented, the revised I&M plan will have to be submitted to and approved by the Executive Officer.

Portable Analyzer Training

In order to assure that persons conducting the portable analyzer testing are properly trained to understand the equipment and the procedures for conducting testing, maintenance and calibration, subparagraph (f)(1)(G) requires persons to take a District-approved training program and obtain a certification issued by the District. SCAQMD intends to conduct the training.

Operating Log

Because dual-fuel engines may consume both liquid and gaseous fuels, proposed paragraph (F)(1)(E) is proposed to require fuel use of both fuels to be logged, instead of either fuel.

New Non-Emergency Electrical Generating Engines

New monitoring procedures are required for the proposed emission standards for new, non-emergency, electrical generating engines. All such engines will be required to monitor: the net electrical output (MW_e-hours) of the engine generator system, which is the difference between the electrical output of the generator and the electricity consumed by the auxiliary equipment necessary to operate the engine generator and heat recovery equipment; and the useful heat recovered (MW_{th}-hours), which is the thermal energy recovered and put to an actual useful purpose.

Emissions in pounds per MW_e-hour must be calculated based on CEMS data, source tests, and weekly emission checks. Mass emissions will be calculated using an F factor method from EPA 40 CFR 60, Appendix A, Method 19, or other approved method. Because Method 19 does not directly address VOC and CO, necessary conversion factors are provided in the rule. An annual report is required to verify compliance with the annual EEF.

Exemptions

Emergency, Flood Control and Fire Fighting Engines

The current rule exempts several types of engines from the subdivision (d) emission limits. Paragraph (h)(2) exempts emergency engines while paragraph (h)(3) exempts fire fighting and flood control engines. The proposed amendments do the following: combine the exemptions into paragraph (h)(2); require all of these engines to operate less than 200 hours per year; and require that permits conditions specifically limit the annual operating hours.

Start up Exemption
The current rule has no exemption during engine startups. The proposed amendments in paragraph (h)(12) will provide an exemption from complying with the emission limits in the rule until emission controls reach operating temperature, but not longer than 15 minutes.

PROJECT BACKGROUND

Current Rule 1110.2
Rule 1110.2 was adopted in August 1990 to control NOx, CO, and VOC from gaseous and liquid-fueled ICEs. For all stationary and portable engines over 50 bhp, it required that either 1) NOx emissions be reduced over 90 percent to one of two compliance limits specified by the rule, or; 2) the engines be permanently removed from service or replaced with electric motors. It was amended in September 1990 to clarify rule language. It was then amended in August and December of 1994 to modify the CO monitoring requirements and to clarify rule language. The amendment of November 1997 eliminated the requirement for continuous monitoring of CO, reduced the source testing requirement from once every year to once every three years, and exempted nonroad engines, including portable engines, from most requirements. The last amendment in June 2005 made the previously exempt agricultural engines subject to the rule.

Regulation XX – RECLAIM
In 1993 SCAQMD adopted Regulation XX – RECLAIM. This regulation established NOx and SOx trading market emission reduction program that required over 300 of the largest NOx and SOx sources in SCAQMD's jurisdiction to meet the requirements of that program rather than the NOx requirements of other SCAQMD Rules. Therefore, while some engines in the SCAQMD's jurisdiction are not subject to the NOx requirements of Rule 1110.2; they are still subject to the VOC and CO requirements of Rule 1110.2.

Affected Sources
PAR 1110.2 applies to stationary and portable reciprocating ICEs over 50 bhp. ICEs generate power by combustion of an air/fuel mixture. In the case of SI engines, a spark plug ignites the air/fuel mixture while a diesel engine relies on heating of the inducted air during the compression stroke to ignite the injected diesel fuel. Most stationary and portable ICEs are used to power pumps, compressors, or electrical generators.

SI engines come in a wide variety of designs such as: two-stroke and four-stroke, rich-burn and lean-burn, turbocharged and naturally-aspirated. SI engines can use one or more fuels, such as natural gas, oil field gas, digester gas, landfill gas, propane, butane, liquefied petroleum gas (LPG), gasoline, methanol and ethanol. ICEs can be used in a wide variety of operating modes such as: emergency operation (i.e. used only during testing, maintenance, and emergencies), seasonal operation, continuous operation, continuous power output, and cyclical power output.

The diesel engine is another type of ICE: specifically, a CI engine, in which the diesel fuel is ignited solely by the high temperature created by compression of the air-fuel mixture, rather than by a separate source of ignition, such as a spark plug, as is the case with SI engines. Similarly to SI engines, there are both two-stroke and four-stroke diesel engines. Most diesel engines are four-stroke, with larger diesels often two-stroke, mainly the large engines in ships and locomotives.

Diesel engines are most commonly used for portable equipment and emergency stationary generators, fire pumps and water pumps. Stationary diesel engines are also used for more routine use at a few locations that have been exempted from complying with Rule 1110.2. These include engines operated by the US Navy on San Clemente Island, and engines at ski resorts. Some diesel engines at RECLAIM facilities also continue to operate because they were exempted from the NOx emission requirements of Rule 1110.2.

Uncontrolled ICEs, even when burning a clean fuel such as natural gas, have extremely high emissions of NOx, CO and HC. Diesel engines not only have significant NOx emissions but also emit PM which has been identified as a Toxic Air Contaminant (TAC) by the CARB. Once a substance is identified as a TAC, the CARB is required by law to determine if there is a need for further control. CARB has adopted ATCM for stationary and portable diesel engines.

SCAQMD BACT Guidelines

NOx, CO and VOC emission levels for stationary engines that are required by SCAQMD's non-major source BACT guidelines are shown in Table 1-4. These limits are typically met by rich-burn engines with larger three-way catalyst (TWC), along with the air-to-fuel ratio controller (AFRC). Lean-burn engines generally come with low-NOx combustion modifications built into the engine by the manufacturer to reduce the emissions part way, and then use SCR plus oxidation catalyst to reduce emissions to BACT levels.

Table 1-4
SCAQMD BACT Guidelines for Stationary Engines at Non-Major Polluting Facilities

	PPMVD, corrected to 15% O2				Apparent Reduction by Control Technology	
	Uncontrolled Emission		BACT			
Criteria Pollutant	**Rich-Burn**	**Lean-Burn**	**Rich-Burn (NSCR)***	**Lean-Burn (SCR + CatOx)**	**Rich-Burn (NSCR), %**	**Lean-Burn (SCR + CatOx), %**
NOx	590	1090	10	9	98+	99+
CO	1629	136	69	33	95+	75+
VOC	23	91	29	25	---	73+

*Assuming engine is 30 percent efficient (HHV basis).

Compliance Issues with Stationary Engines

SCAQMD Compliance Testing

For engine used continuously, it is typical to require an oil change once a month, and tune-ups every two months, including new spark plugs and O2 sensors. The current rule requires no checking of emissions during these numerous engine maintenance operations.

Aside from normal maintenance, engines or emission control systems can fail which can cause excess emissions. The following is list of possible engine or emission control system failures:

- A bad spark plug
- A faulty spark plug wire
- A failed O2 sensor
- A O2 sensor for which the mV signal has drifted
- A catalyst that has plugged due to ash from lubrication oil blowby
- A catalyst that has become deactivated due to poisoning from ash blowby or excess exhaust temperature
- A catalyst that degrades from vibration allowing bypassing of the catalyst
- A failed AFRC
- A AFRC that is not properly recalibrated after an O2 sensor replacement

In recent years, SCAQMD enforcement personnel acquired portable analyzers capable of measuring NOx, CO and O2 concentrations in the exhaust of combustion equipment. These analyzers are not expected to be as accurate as a Method 100.1 source test, but they are easier and faster to set up and use, and can detect emissions and compliance problems. SCAQMD inspectors use the portable analyzers to conduct unannounced emission tests and compliance verification on various types of combustion equipment.

These emission tests have shown that rich-burn ICEs, have very high non-compliance rates and very high excess emissions. The Preliminary Staff Report PAR 1110.2 states that more than half of all engines tested were not in compliance with both NOx and CO emission limits. Rich-burn engines had significantly higher non-compliance rates than lean-burn engines. Extrapolating the results for the tested engines to the entire stationary, non-emergency engine inventory of nearly 1,000 engines results in estimated excess emissions of 1.2 tons per day of NOx and 39.9 tons per day of CO.

To verify that the emission violations had been corrected 37 engines were retested. The compliance rate, however, only improved from 44 percent of all first tests to 65 percent of all retests.

Compliance Demonstration

Current regulations require ICEs to demonstrate emission compliance by an emission source test only once every three years. If the tests show non-compliance, only major sources (Title V) are required to report the results to SCAQMD. Based on SCAQMD enforcement compliance testing the three year period between compliance demonstrations does not appear to ensure compliance.

EPA Guidance

EPA proposed the disapproval of Rule 1110.2 and recommended the following changes to enable approval of the rule:[4]

- An inspection and monitoring plan similar to CARB' RACT/BARCT document;
- Source testing every two years or 8,760 hours;
- Source testing at peak load as well as at under typical duty cycles; and
- A removal of the exemptions for engines at ski resorts, the far eastern portion of Riverside County, and San Clemente Island.

Senate Bill 1298

Senate Bill 1298[5] was adopted in 2000 by the California state legislature to close a loophole for small electric generators that were exempt from local district permits and not required to have emission controls. In accordance with the law, CARB adopted the Distributed Generation Certification Program[6] for small generators that are exempt from local district permitting requirements. In SCAQMD, this includes ICE generators of 50 hp or less, microturbines, and fuel cells. As of January 1, 2007 these electrical generation technologies may only be sold in California if they are certified by CARB to have emissions equivalent or better than large central generating stations equipped with BACT.

SB 1298 also established a goal to have local districts require permitted distributed generation (DG) equipment to meet the same emissions levels by the earliest practicable date.

DG Technologies that Meet CARB 2007 DG Standards

CARB has certified that the following DG equipment meet the 2007 standards.

Table 1-5
Certified Technologies to CARB 2007 DG Standards

Company Name	Technology
United Technologies Corporation Fuel Cells	200 kW, Phosphoric Acid Fuel Cell
FuelCell Energy, Inc.	250 kW, DFC300A Fuel Cell
Plug Power Inc.	5 kW, GenSys™ 5C Fuel Cell
FuelCell Energy, Inc.	1 MW, DFC1500 Fuel Cell
Ingersoll-Rand Energy Systems	250 kW, 250SM Microturbine
FuelCell Energy, Inc.	250 kW, DFC300MA Fuel Cell
ReliOn, Inc.	2 kW, T-2000 hydrogen-fueled fuel cell
ReliOn, Inc.	1.2 kW, T-1000 hydrogen-fueled fuel cell

The following DG technologies don't require CARB certification, because they normally get SCAQMD permits, but they can also meet CARB's 2007 emission standards:

[4] Memorandum from Andrew Steckel of USEPA to Laki Tisopulos of SCAQMD dated March 31, 2005.
[5] Sections 41514.9 and 41514.10 of the California State Health and Safety Code
[6] Sections 94200-94214, in Article 3, Subchapter 8, Chapter 1, Division 3 of Title 17, California Code of Regulations

- Kawasaki GPB15X Gas Turbine--1.423 gross MW at ISO conditions (sea level, 59°F), guaranteed emission limits of 2.5 ppm NOx, six ppm CO and two ppm VOC, all dry basis, corrected to 15 percent O2, down to 70 percent of rated load. These emission limits together with heat input of 20.7 MMBtu/hr (LHV) and 53.7 percent waste heat recovery specified by the manufacturer meet the CARB 2007 standards.
- Large combustion gas turbines with combined heat and power (CHP). These are very similar to the central station combined-cycle power plants that are the basis of the 2007 CARB DG standards.

In addition, facilities may install other DG technologies such as: zero-emission solar or wind DG. All of the above technologies are either inherently low-emission, or will have CEMS to assure proper operation of their add-on emission controls.

EMISSIONS INVENTORY

Portable Engines

CARB estimates that in 2000 17,500 portable diesel engines in California emitted 67.1 tons per day of NOx, 6.7 tons per day of reactive organic gas (ROG) and 4.2 tons per day of PM. Emissions in SCAQMD would be about 45 percent of this amount. These emissions should gradually decline as newer CARB-certified portable engines replace older, higher emitting engines.

Stationary Non-Agricultural Engines

The 1990 staff report for proposed Rule 1110.2 estimated that Rule 1110.2 would reduce NOx emissions of 1,289 stationary, non-emergency engines from 28.0 tons per day to 2.9 tons per day. Exemptions in 1997 for ski resorts and San Clemente Island increased the allowable emissions by 1.35 tons per day to an estimated 4.25 tons per day.

Stationary Engine Survey

To update this information as well as gather other key information for non-agricultural engines that are affected by the rule, staff conducted a survey in 2005 of non-agricultural, stationary, non-emergency engines. A total of 580 facilities were contacted, and 313 of those facilities responded (54 percent facility response rate). The survey collected data for 631 out of a total of 907 active engines (70 percent response rate based on number of engines).

Emissions were calculated based on fuel consumption data gathered via the survey, Rule 1110.2 or BACT emission limits, and source test data fro non-BACT engines. The resulting calculated total emissions for all survey engines were scaled up to account for the 70 percent response rate. The resulting total calculated emissions for all stationary, non-emergency engines in the district, in tons per day, are 2.84 NOx, 1.19 VOC and 10.35 CO. The calculated current NOx emissions indicate that substantial progress has been made since 1990, and the calculated NOx emissions are probably less than the 4.25 tons per day level that was expected.

As mentioned earlier in the report, a program of unannounced compliance testing conducted by SCAQMD's Compliance department revealed that, although engines can generally meet emission limits when emission control systems are properly maintained and adjusted as is generally the case at the time of source testing; emissions during normal operation frequently exceed the emission limits. The tendency for an engine to have excess emissions will differ depending upon whether it is a rich-burn or lean-burn engine, what emission limits it must meet (BACT or Rule 1110.2) and whether or not it has a CEMS. Table 1-6 shows the average ratio of measured emissions to allowed emissions found in the testing program with engines categorized based on these three parameters.

Regulation XX - RECLAIM

In 1993 SCAQMD adopted Regulation XX – RECLAIM. This regulation established NOx and SOx trading market emission reduction program that required over 300 of the largest sources in SCAQMD to meet the requirements of that program rather than the NOx requirements of other SCAQMD Rules. Therefore, while some engines in SCAQMD are not subject to the NOx requirements of Rule 1110.2; they are still subject to the VOC and CO requirements of Rule 1110.2.

Table 1-6

Average Ratio of Measured Emission to Allowed Emission Found in Unannounced Testing

Rich/Lean	Limits	CEMS	Tests	NOx	CO
Lean	BACT	No	3	1.81	0.33
Lean	BACT	Yes	7	0.76	0.39
Lean	Rule	No	1	0.89	0.10
Rich	BACT	No	169	5.19	5.21
Rich	BACT	Yes	8	0.11	37.76
Rich	Rule	No	39	2.12	0.70

Excess emissions of both NOx and CO were clearly evident from rich-burn engines with BACT limits not having CEMS. Excess emissions of CO were evident from rich-burn engines with BACT limits having CEMS and of NOx from rich-burn engines with Rule 1110.2 limits not having CEMS. Although there was some suggestion of excess NOx emissions from lean-burn engines with BACT limits not having CEMS, the number of tests was considered too small to be conclusive, and lean-burn engines are less likely to have large exceedances. There were no tests on rich-burn engines with Rule 1110.2 limits having CEMS.

To estimate the extent of excess emissions from the engine population in the district, staff applied factors to the allowed emissions from each engine for which survey data were available. These factors were based on the results of unannounced testing summarized in Table 1-6. To eliminate excess VOC emission from each engine, the CO factor was also applied to VOC based on the general observation that these pollutants generally trend together. Again, scaling the results based on the 70 percent survey response rate, the estimated excess emissions in tons per day are 1.20 NOx, 7.01 VOC and 39.9 CO.

Table 1-7 summarizes the calculated emissions based on the survey data, the estimated excess emissions based on the average exceedance factors found in compliance testing and the resulting total calculated/estimated emissions from stationary, non-emergency engines.

Table 1-7
Emissions from Stationary, Non-Emergency Engines (tons per day)

Description	NOx	CO	VOC
Calculated Based on Limits and Source Tests	2.84	10.35	1.19
Estimated Excess Emissions	1.20	39.9	7.01
Totals	4.04	50.24	8.20

CONTROL TECHNOLOGY

Without any emission controls, ICEs have the highest emissions of all combustion equipment in terms of emissions per unit of fuel use. Fortunately, there are emission controls for ICEs. They include combustion modifications and add-on control technologies. The types of controls that are used depend on the fuel used and whether the ICE is rich-burn or lean-burn.

Spark-Ignition (SI) Engine Emissions and Emission Control Technologies

SI Engines and Uncontrolled Emissions

SI engines fall into two major design categories. Four-stroke, rich-burn engines are designed to operate close to stoichiometric conditions. In other words, just the necessary amount of air is drawn to combust the fuel and little, if any, more. These engines operate with exhaust gas oxygen content very near zero. The other category is lean-burn engines, which are designed to draw substantially more air than is required for combustion and operate with a high level of exhaust gas oxygen, typically over five percent. Larger engines tend to be lean-burn, and smaller engines tend to be rich-burn. Typical emissions of NOx, CO and VOC from uncontrolled natural gas-fired engines are listed in Table 1-8. The emission factors in the table are from U.S. EPA's AP-42[7] NOx emissions from engines operating on landfill or digester gas should be significantly lower due to the thermal diluent effect of CO2 present in these types of waste gas.

Table 1-8
Uncontrolled Emissions from Natural Gas-Fired SI Engines *

Description	Rich-Burn, lbs/MMBtu$_{HHV}$	Lean-Burn, lbs/MMBtu$_{HHV}$
NOx	2.21	4.08
CO	3.72	0.317
VOC	0.0296	0.118
Description	**Rich-Burn, ppmvd at 15% O_2**	**Lean-Burn, ppmvd at 15% O_2**
NOx	590	1090
CO	1629	139
VOC	23	91

*g/Bhp-hr = lb/MMBtu x 1.15 / (%EFF$_{HHV}$/100)
ppmvdat15%O2 = lb/MMBtu x F (F = 267 for NOx, 438 for CO, 767 for VOC as methane)

[7] U.S. EPA AP-42 Compilation of Air Pollution Emission Factors, Tables 3.2-2 and 3.2-3.

CARB RACT/BARCT Determination

In November 2001, CARB published a (retrofit available control technology) RACT/(best available retrofit control technology) BARCT determination[8] for stationary SI engines. This determination, while not aggressive for CO or VOC, identified a number of NOx control technologies that are effective for stationary SI engines (Table 1-9) and recommended significant reductions in NOx (Table 1-10). Lean-burn SI engines that are subject only to Rule 1110.2, and not to BACT, will generally be equipped with low-emission combustion improvements, whereas rich-burn SI engines will have a TWC, also known as non-selective catalytic reduction (NSCR), which along with accurate control of the air/fuel ratio to near stoichiometric conditions, simultaneously reduces the three pollutants NOx, CO and VOC.

Table 1-9
NOx Control Technologies for Stationary SI Engines

Technology	NOx Reduction Capability, %	Comments
Ignition Timing Retard	15-30	Reduces efficiency by up to five percent
Pre-Stratified Charge (PSC)	80+	Not suitable for lean-burn engines
Low-Emission Combustion Modifications	80+	Pre-combustion chamber, leaning, ignition system improvement, turbocharger, air/fuel ratio control system. Retrofit kits are available for some engines.
Turbocharger with Aftercooler	3-35	
Exhaust Gas Recirculation (EGR)	30	
Non-selective Catalytic Reduction (NSCR)	90+	Three-way catalyst—reduces NOx, CO and VOC. Not suitable for lean-burn engines.
Selective Catalytic Reduction (SCR)	80+	Requires injection of urea or ammonia to react with NOx. Unreacted ammonia is emitted. Oxidation catalyst is normally included to reduce CO and VOC emissions.

Table 1-10
CARB NOx RACT/BARCT Determination for Stationary SI Engines
(ppmvd corrected to 15 percent O2)

Control	Rich-Burn	Lean-Burn
RACT	90% control or 50 ppm NSCR, PSC for waste gases	80% control or 125 ppm Low-Emission Combustion or SCR
BARCT	96% control or 25 ppm NSCR, Inspection & Maintenance Program Waste Gases: 90% control or 50 ppm PSC	90% control or 65 ppm Low-Emission Combustion Mod's or SCR

[8] CARB, "Determination of Reasonably Available Control Technology and Best Available Retrofit Control Technology for Stationary Spark-Ignited Internal Combustion Engines", November 2001.

Rich-Burn Engine Control Technology Issues
When a rich-burn engine with a TWC and AFRC is properly tuned and source tested, excellent emission reductions are achieved. It is the job of AFRC and O2 sensor to maintain the engine air to fuel ratio at the right point.

Before the once every three year source test is conducted, engines operators assure that engines are in good operating condition and properly tuned to the correct air-to-fuel ratio.

The oxygen sensor is a critical component of the emission control system. Based on information from several sources, it appears that the O2 sensor set point that works upon initial startup will not be the proper set point as the O2 sensor ages[9]. The emissions must be periodically measured and the oxygen sensor set point readjusted.

Rich-Burn Engine Demonstration Projects
The Rule 1110.2 Industry Stakeholder Work Group, in cooperation with SCAQMD, conducted some projects to demonstrate that modern AFRCs could: control rich-burn engines to comply with Rule 1110.2 and BACT emission limits; and alarm operators when there are excess emissions. The projects did not achieve the desired results. They demonstrated that modern AFRCs are not adequate and that additional periodic monitoring is needed.

Biogas Engine Emissions and Control Technologies
Biogas (digestor or landfill gas) engines are a special case. The engines are generally larger four-stroke, lean-burn engines very similar to natural gas engines. Because the facilities have argued that contaminants in the fuel, like siloxane, are incompatible with catalytic after-treatment devices, biogas engines have generally not been required to install oxidation catalysts and SCR units that natural gas engines use. As a result, biogas engine emissions are the highest of all engines, even higher that a diesel engine with BACT.

Figure 1-2 demonstrates that the emissions from biogas engines, even when complying with BACT, far exceed natural gas (NG) engines and large central generating stations.

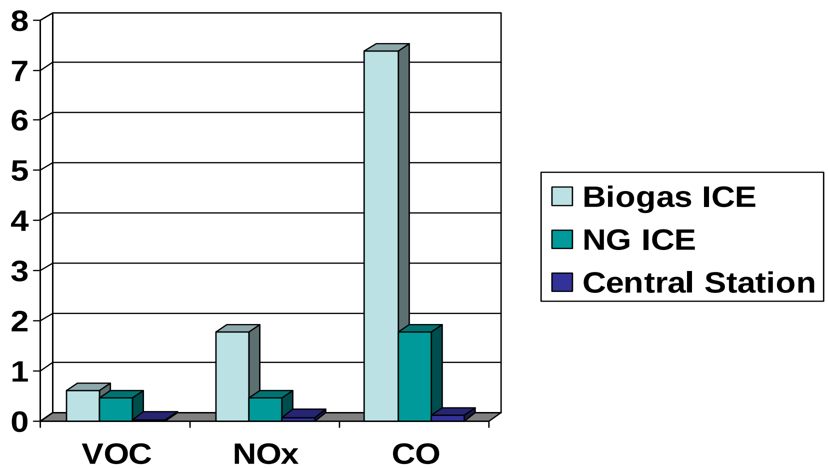
However, recent developments indicated that new technologies may allow emissions as low as with natural gas engines. Landfills in City of Industry and Brea have installed fuel gas treatment equipment to remove the contaminants and allow catalytic controls. Both have oxidation catalysts, while the City of Industry has also installed SCR for NOx control. There are also non-catalytic controls available. A selective non-catalytic NOx/VOC and CO control device by NOxTech has been installed on a landfill gas engine in Woodville, California. Landfills in Italy have installed engines with CL.AIR® non-catalytic VOC/CO control devices, both available from Jenbacher, part of GE Energy.

Diesel Engine Emissions and Emission Control Technologies
U.S. EPA's AP-42[10] lists uncontrolled industrial diesel engine emissions in terms of grams per bhp-hour as 14.0 NOx, 3.03 CO, and 1.12 VOC. Since 1996, nonroad diesel engines have been regulated at the federal and state levels through a certification program requiring that the

[9] Eastwood, Chapter Six for a discussion of oxygen sensor aging.
[10] U.S. EPA AP-42 Compilation of Air Pollution Emission Factors, Table 3.3-1.

manufacturers certify their engine models to meet certain emission standards, which become progressively more stringent over time. California's nonroad emission standards are the same as the federal nonroad standards. The nonroad emission standards for gaseous pollutants are shown in Table 1-11. The Tier 4 engines over 75 bhp would comply with Rule 1110.2, but they will not be available until 2014.

Figure 1-2. BACT for Biogas ICEs, NG ICEs vs. Central Generating Station BACT (lbs/MW-hr)



Add-on control technologies that are suitable for diesel engines include SCR for NOx and oxidation catalysts for reduction of CO and VOC. Both of these technologies have been successfully applied to diesel engines. SCR involves injection of urea or ammonia into the flue gas upstream of the catalyst and results in emissions of small amounts of unreacted ammonia. Application of these technologies to a large Tier 1 diesel engine located at a ski resort in the SCAQMD achieved the NOx, CO and VOC emissions shown in Table 1-12. Assuming that the engine was designed for emissions to be approximately 20 percent below the Tier 1 standards, the apparent emission reductions achieved by the technologies are 90 percent for NOx, 99 percent for CO and 74 percent for VOC. Because of the high costs of the add-on control equipment for a diesel engine, compared to a SI engine, few diesels were retrofitted to comply with Rule 1110.2. Some became subject to the RECLAIM program, some were exempted from Rule 1110.2 and others were removed from service.

Emulsified fuel is another technology that can be applied to a stationary diesel engine. Emulsified fuel contains water, which has been blended into the fuel using appropriate blending equipment and an additive to create a stable mixture. Separation of the water can, however, occur if the fuel is in storage for too long. Presence of water in the fuel improves combustion while also lowering the flame temperature. It has been applied primarily to on-road and nonroad diesel engines and primarily for reduction of particulate emissions. However, it reduces NOx by only 10 to 20 percent[11].

Although SOx and PM emissions are not addressed by Rule 1110.2, SOx emissions are now well controlled with ultra low sulfur diesel fuel (less than 15 ppm by weight) required by Rule 431.2. PM is also well controlled by diesel particulate filters.

Table 1-11
U.S. EPA Nonroad Diesel Gaseous Emission Standards—NOx or (NOx+NMHC)/NMHC/CO (g/Bhp-hr)

Engine Power, bhp	Tier 1	Tier 2	Tier 3	Tier 4 Interim	Tier 4 Final
50 to <75	1998 6.9 -- --	2004 (5.6) -- 3.7	2008 (3.5) -- 3.7		2012 (3.5) 3.7
75 to <100	1998 6.9 -- --	2004 (5.6) -- 3.7	2008 (3.5) -- 3.7	2012 2.6 0.14 3.7	2015 0.3 0.14 3.7
100 to <175	1997 6.9 -- --	2003 (4.9) -- 3.7	2007 (3.0) -- 3.7	2012 2.6 0.14 3.7	2015 0.3 0.14 3.7
175 to <300	1996 6.9 1.0 8.5	2003 (4.9) -- 2.6	2006 (3.0) -- 2.6	2011 1.5 0.14 2.6	2014 0.3 0.14 2.6
300 to <600	1996 6.9 1.0 8.5	2001 (4.8) -- 2.6	2005 (3.0) -- 2.6	2011 1.5 0.14 2.6	2014 0.3 0.14 2.6
600 to <750	1996 6.9 1.0 8.5	2002 (4.8) -- 2.6	2005 (3.0) -- 2.6	2011 1.5 0.14 2.6	2014 0.3 0.14 2.6
≥750	2000 6.9 1.0 8.5	2006 (4.8) -- 2.6		2011 2.6 0.3 2.6	2015 2.6 0.14 2.6

Note: ppmvdat15%O2 = g/Bhp-hr x (%EFF_{HHV}/100) / 1.15 x F (F= 253 for NOx, 415 for CO, 727 for VOC as methane)

[11] http://www.epa.gov/region1/eco/diesel/retrofits.html#doc

Table 1-12
Emission from Diesel Engine at a Ski Resort

Pollutant	Concentration in Exhaust Gas, ppmvd at 15% O2	Emission Rate, g/Bhp-hr	Tier 1 Emission Standard, g/Bhp-hr	Apparent Reduction Based on Uncontrolled Level = Tier 1 Less 20%, %
NOx	45	0.546	6.9	90
CO	5	0.037	8.5	99
VOC	49	0.21	1.0	74
Ammonia	0.6	--	--	--

Other Technology Options
For some stationary engines affected by the proposed Rule 1110.2 amendments, other options may be better than adding control equipment to the existing engine to bring the engine into compliance with the rule. One option for engines that drive pumps or compressors is to replace the engine with an electric motor. Most operators that choose an engine instead of an electric motor did so because of the lower energy cost of natural gas versus electricity. However, due to recent increases in natural gas costs, and the additional costs for engines such as maintenance, permits and source testing, and emission fees, electric motors are now a more attractive option.

For ICE electrical generators, operators may choose to replace the engines with cleaner technologies such as fuel cells, solar photovoltaic systems, or gas turbines. Or they could simply decide to buy the clean electric power available from their electric utility.

ALTERNATIVES
The Draft EA will discuss and compare alternatives to the proposed project as required by CEQA and by SCAQMD Rule 110. Alternatives must include realistic measures for attaining the basic objectives of the proposed project and provide a means for evaluating the comparative merits of each alternative. In addition, the range of alternatives must be sufficient to permit a reasoned choice and it need not include every conceivable project alternative. The key issue is whether the selection and discussion of alternatives fosters informed decision making and public participation. A CEQA document need not consider an alternative whose effect cannot be reasonably ascertained and whose implementation is remote and speculative. Suggestions on alternatives submitted by the public will be evaluated for inclusion in the Draft EA.

SCAQMD Rule 110 does not impose any greater requirements for a discussion of project alternatives in an environmental assessment than is required for an Environmental Impact Report under CEQA. Alternatives will be developed based in part on the major components of the proposed amended rule. The rationale for selecting alternatives rests on CEQA's requirement to present "realistic" alternatives; that is alternatives that can actually be implemented. CEQA requires an evaluation of a "No Project Alternative." SCAQMD’s policy document Environmental Justice Program Enhancements for fiscal year (FY) 2002-03, Enhancement II-1 recommends that all SCAQMD CEQA assessments include a feasible project alternative with the lowest air toxics emissions. In other words, for any major equipment or process type under the scope of the proposed project that creates a significant environmental impact, at least one alternative, where feasible, shall be considered from a "least harmful" perspective with regard to hazardous air emissions.

The Governing Board may choose to adopt any portion or all of any alternative presented in the EA. The Governing Board is able to adopt any portion or all of any of the alternatives because the impacts of each alternative will be fully disclosed to the public and the public will have the opportunity to comment on the alternatives and impacts generated by each alternative.

Written suggestions on potential project alternatives received during the comment period for the Initial Study will be considered when preparing the Draft EA.

CHAPTER 2 - ENVIRONMENTAL CHECKLIST

Introduction

General Information

Environmental Factors Potentially Affected

Determination

Environmental Checklist and Discussion

INTRODUCTION

The environmental checklist provides a standard evaluation tool to identify a project's potential adverse environmental impacts. This checklist identifies and evaluates potential adverse environmental impacts that may be created by the proposed project.

GENERAL INFORMATION

Project Title:	Proposed Rule 1110.2 – Emissions from Gaseous- and Liquid-Fueled Engines
Lead Agency Name:	South Coast Air Quality Management District
Lead Agency Address:	21865 Copley Drive Diamond Bar, CA 91765
CEQA Contact Person:	Mr. James Koizumi (909) 396-3234
Rule 1110.2 Contact People	Mr. Alfonzo Baez (909) 396-2516 Dr. Howard Lange (909) 396-3658 Mr. Martin Kay (909) 396-3115
Project Sponsor's Name:	South Coast Air Quality Management District
Project Sponsor's Address:	21865 Copley Drive Diamond Bar, CA 91765
General Plan Designation:	Not applicable
Zoning:	Not applicable
Description of Project:	PAR 1110.2 would partially implement 2007 AQMP Control Measure MSC–01 – Facility Modernization. PAR 1110.2 would also increase engine compliance by better monitoring, recordkeeping and reporting. PAR 1110.2 would implement SB 1298 distributed generation emission standards for new electrical generating engines, as well as, address issues EPA has with the current Rule 1110.2. The implementation of PAR 1101.1 is expected to reduce NOx emissions by 5,520 pounds per day, VOCs by 14,762 pounds per day and CO emissions by 93,256 pounds per day.
Surrounding Land Uses and Setting:	Not applicable
Other Public Agencies Whose Approval is Required:	Not applicable

ENVIRONMENTAL FACTORS POTENTIALLY AFFECTED

The following environmental impact areas have been assessed to determine their potential to be affected by the proposed project. As indicated by the checklist on the following pages, environmental topics marked with an "✓" may be adversely affected by the proposed project. An explanation relative to the determination of impacts can be found following the checklist for each area.

☐	Aesthetics	☐	Agriculture Resources	☑	Air Quality
☐	Biological Resources	☐	Cultural Resources	☑	Energy
☐	Geology/Soils	☑	Hazards & Hazardous Materials	☐	Hydrology/ Water Quality
☐	Land Use/Planning	☐	Mineral Resources	☐	Noise
☐	Population/Housing	☐	Public Services	☐	Recreation
☑	Solid/Hazardous Waste	☐	Transportation/ Traffic	☑	Mandatory Findings of Significance

DETERMINATION

On the basis of this initial evaluation:

☐ I find the proposed project, in accordance with those findings made pursuant to CEQA Guideline §15252, COULD NOT have a significant effect on the environment, and that an ENVIRONMENTAL ASSESSMENT with no significant impacts will be prepared.

☐ I find that although the proposed project could have a significant effect on the environment, there will NOT be significant effects in this case because revisions in the project have been made by or agreed to by the project proponent. An ENVIRONMENTAL ASSESSMENT with no significant impacts will be prepared.

☑ I find that the proposed project MAY have a significant effect(s) on the environment, and an ENVIRONMENTAL ASSESSMENT will be prepared.

☐ I find that the proposed project MAY have a "potentially significant impact" on the environment, but at least one effect 1) has been adequately analyzed in an earlier document pursuant to applicable legal standards, and 2) has been addressed by mitigation measures based on the earlier analysis as described on attached sheets. An ENVIRONMENTAL ASSESSMENT is required, but it must analyze only the effects that remain to be addressed.

☐ I find that although the proposed project could have a significant effect on the environment, because all potentially significant effects (a) have been analyzed adequately in an earlier ENVIRONMENTAL ASSESSMENT pursuant to applicable standards, and (b) have been avoided or mitigated pursuant to that earlier ENVIRONMENTAL ASSESSMENT, including revisions or mitigation measures that are imposed upon the proposed project, nothing further is required.

Date: April 20, 2007 **Signature:** Steve Smith

Steve Smith, Ph.D.
Program Supervisor

ENVIRONMENTAL CHECKLIST AND DISCUSSION

As discussed in Chapter 1, the main focus of the proposed rule is to reduce NOx, VOC and CO emissions from gaseous- and liquid-fueled ICE. The proposed amendments would increase monitoring requirements; require stationary, non-emergency engineers to meet emission standards equivalent to BACT; require new electrical generating engines to meet the same requirements as large central power plants, and clarify portable engine requirements.

Compliance with PAR 1110.2 may require oxidation catalyst, SCR, and replacement of two-stroke engines with electric motors. Facility operators may need to install CEMS, CO analyzers, AFRC and oxygen sensor, and infrastructure to facilitate monitoring and source testing (sampling ports, platforms, ladders, etc.).

Construction

New Gaseous- and Liquid Fueled Engines

PAR 1110.2 would not cause new development. Therefore, PAR 1110.2 is not expected to require the installation of any new engines. PAR 1110.2 may impact the choice of engine installed, BACT installed and monitoring equipment required at new facilities. The number and impact of new engines is speculative and therefore will not be evaluated in this CEQA analysis. However, new engines would be required to enter the permit process before construction. All permitted equipment is required to have a CEQA evaluation. Impacts from the construction of new engines would be evaluated at that time. No change in fuel type is expected.

Existing Gaseous- and Liquid Fueled Engines

PAR 1110.2 has a variety of requirements that compliance dates from 2007 to 2012. Most of the construction would occur within the first two years after adoption of the amended rule. Based on a survey of facilities with gaseous- and liquid-fuel engines, SCAQMD staff estimates that 412 engines would require additional source testing (one additional test every six years) staffing in 2007; 620 engine systems would require minor construction to install infrastructure (sampling ports, platforms, safe access and utilities) and air/fuel ratio controllers by June 2008; 490 engines require installation of CO analyzers and/or NOx-CO CEMS by July 2008; 22 engines would need replacement with electric motors by July 1, 2010; 30 engines would need oxidation catalyst by July 2011; 300 facilities would need modification of three-way catalyst by July 2011; and 78 would need SCR by July 2012. The Landfill Gas to Energy Coalition is concerned that the cost of install in SCR would make flaring an economical alternative to installing SCR. The possibility replacing engines with flares will be examined in the Draft EIR.

Construction or modification of control technologies, engine replacement with electric motor or installation of infrastructure may require cranes, loaders, forklifts, welders and generator sets. Installation of controllers, analyzers, and CEMS systems are likely to require less heavy equipment. All construction would require delivery truck and worker trips. Based on the above, SCAQMD staff assumes that construction would occur at approximately 15 facilities per day beginning in 2007 through 2008. Between 2009 to 2012, construction would occur at one or two facilities per day.

Operations

Emission reductions associated with compliant gaseous- and liquid-fueled engines are presented in Chapter 1. The operations of compliant gaseous- and liquid-fueled engines would result in reductions in all criteria and toxic emissions.

PAR 1110.2 compliant gaseous- and liquid-fueled engines control emissions by burning fuel more efficiently because engine improvements, better operation and maintenance; and/or by control technology.

		Potentially Significant Impact	Less Than Significant Impact	No Impact
I.	**AESTHETICS.** Would the project:			
a)	Have a substantial adverse effect on a scenic vista?	☐	☐	☑
b)	Substantially damage scenic resources, including, but not limited to, trees, rock outcroppings, and historic buildings within a state scenic highway?	☐	☐	☑
c)	Substantially degrade the existing visual character or quality of the site and its surroundings?	☐	☐	☑
d)	Create a new source of substantial light or glare which would adversely affect day or nighttime views in the area?	☐	☐	☑

Significance Criteria

The proposed project impacts on aesthetics will be considered significant if:

- The project will block views from a scenic highway or corridor.
- The project will adversely affect the visual continuity of the surrounding area.
- The impacts on light and glare will be considered significant if the project adds lighting which would add glare to residential areas or sensitive receptors.

Discussion

I.a), b), c) & d) PAR 1110.2 would reduce NOx, VOCs and CO from gaseous- and liquid-fueled ICE. Compliance includes retrofit or replacement of equipment to achieve BACT emission levels and improving monitoring, recordkeeping and reporting for better compliance.

PA 1110.2 would not require any new development, but may require minor modifications to buildings or other structures for retrofit or replacement of existing engines; and new, retrofit, or replacement control equipment and monitoring equipment to comply with the proposed rule. PAR 1110.2 may require replacing or altering existing equipment.

Staff estimates that commercial and industrial facilities may install new, retrofit or replace existing ICE, control technology, and/or monitoring equipment. The retrofitted, replaced or new equipment would be located within the boundaries of existing commercial or industrial facilities near to existing ICE systems. And therefore, would not be substantially different in physical appearance than other existing commercial or industrial equipment at these facilities, it is not expected that the retrofitted, replaced and/or new equipment would obstruct scenic resources or degrade the existing visual character of a site, including but not limited to: trees, rock outcroppings, or historic buildings.

Any new development would not be a result of business decisions and not PAR 1110.2. PAR 1110.2 would affect the type of ICE and control systems installed in new developments. However, it is expected that PAR 1110.2 compliant equipment would be similar in aesthetic character to non-compliant PAR 1110.2. Therefore, installation of PAR 1110.2 compliant equipment is not expected to adversely affect aesthetics.

In addition, retrofitted, replaced or new equipment would require new permits or modifications of existing permits. New and modified permit applications require CEQA review in the form of the 400 CEQA form. Even though no aesthetic impacts are expect from PAR 1110.2, the new, retrofit or replacement equipment will be examined for any potential adverse impacts as apart of the normal permitting process.

Additional light or glare would not be created which would adversely affect day or nighttime views in the area since no light generating equipment would be required to comply with proposed rule.

Based upon these considerations, significant adverse aesthetics impacts are not anticipated and will not be further analyzed in the Draft EA. Since no significant aesthetics impacts were identified, no mitigation measures are necessary or required.

	Potentially Significant Impact	**Less Than Significant Impact**	**No Impact**
II. AGRICULTURE RESOURCES. Would the project:			
a) Convert Prime Farmland, Unique Farmland, or Farmland of Statewide Importance (Farmland), as shown on the maps prepared pursuant to the Farmland mapping and Monitoring Program of the California Resources Agency, to non- agricultural use?	☐	☐	☑

		Potentially Significant Impact	Less Than Significant Impact	No Impact
b)	Conflict with existing zoning for agricultural use, or a Williamson Act contract?	☐	☐	☑
c)	Involve other changes in the existing environment which, due to their location or nature, could result in conversion of Farmland, to non-agricultural use?	☐	☐	☑

Significance Criteria

Project-related impacts on agricultural resources will be considered significant if any of the following conditions are met:

- The proposed project conflicts with existing zoning or agricultural use or Williamson Act contracts.
- The proposed project will convert prime farmland, unique farmland or farmland of statewide importance as shown on the maps prepared pursuant to the farmland mapping and monitoring program of the California Resources Agency, to non-agricultural use.
- The proposed project would involve changes in the existing environment, which due to their location or nature, could result in conversion of farmland to non-agricultural uses.

Discussion

II.a), b), & c) PAR 1110.2 would reduce NOx, VOCs and CO from gaseous- and liquid-fueled ICE. Compliance includes retrofit or replacement of equipment to achieve BACT emission levels and improving monitoring, recordkeeping and reporting for better compliance.

Existing Facilities

PAR 1110.2 may require replacing or altering existing equipment. Any replacement or retrofit construction would occur at existing commercial or industrial facilities. Therefore, PAR 1110.2 is not expected to convert any classification of farmland to non-agricultural use or conflict with zoning for agricultural use or a Williamson Act contract.

In addition, retrofitted, replaced or new equipment would require new permits or modifications of existing permits. New and modified permit applications require CEQA review in the form of the 400 CEQA form. Even though no agricultural impacts are expect from PAR 1110.2, the new, retrofit or replacement equipment will be examined for any potential adverse impacts as apart of the normal permitting process.

New Development

PAR 1110.2 would not require any new development, but may require minor modifications to buildings or other structures for retrofit or replacement of existing engines; and new, retrofit, or replacement control equipment and monitoring equipment to comply with the proposed rule. New development may be impacted by PAR 1110.2; however, PAR 1110.2 would not be direct or indirect cause of the new development. Similar construction at existing facilities, construction of ICEs, control technology and monitoring equipment is expected to be pre-manufactured and dropped in place.

Based upon these considerations, significant agricultural resource impacts are not anticipated and will not be further analyzed in the Draft EA. Since no significant agriculture resources impacts were identified, no mitigation measures are necessary or required.

	Potentially Significant Impact	Less Than Significant Impact	No Impact
III. AIR QUALITY. Would the project:			
a) Conflict with or obstruct implementation of the applicable air quality plan?	☐	☑	☐
b) Violate any air quality standard or contribute to an existing or projected air quality violation?	☑	☐	☐
c) Result in a cumulatively considerable net increase of any criteria pollutant for which the project region is non-attainment under an applicable federal or state ambient air quality standard (including releasing emissions that exceed quantitative thresholds for ozone precursors)?	☑	☐	☐
d) Expose sensitive receptors to substantial pollutant concentrations?	☑	☐	☐
e) Create objectionable odors affecting a substantial number of people?	☐	☐	☐
f) Diminish an existing air quality rule or future compliance requirement resulting in a significant increase in air pollutant(s)?	☐	☐	☑

III.a) and f) Attainment of the state and federal ambient air quality standards protects sensitive receptors and the public in general from the adverse effects of criteria pollutants which are known to have adverse human health effects. PAR 1110.2 contributes directly to carrying out the goals of the 2007 Draft AQMP by implementing control measure MSC-01 – Facility Modernization. Consistent with control measure MSC-01, PAR 1110.2 is expected to reduce NOx, VOC and CO emissions from all affected source categories, which in turn, will contribute to attaining the state and federal ambient air quality standards. Thus, because PAR 1110.2 implements control measure MSC-01 from the 2007 Draft AQMP, it is not expected to conflict or obstruct implementation of the applicable AQMP.

PAR 1110.2 would make emission limits, monitoring and reporting more stringent. PAR 1110.2 would not diminish the requirements of any other rule or regulation. Therefore, implementing PAR 1110.2 would not diminish an existing air quality rule or future compliance requirement, nor conflict with or obstruct implementation of the applicable air quality plan.

While there are no significance thresholds for greenhouse gases, CO2 emissions from PAR 1110.2 will be reported in the Draft EA for completeness.

III.b) & c)

Air Quality Significance Criteria
To determine whether or not air quality impacts from adopting and implementing the proposed amendments are significant, impacts will be evaluated and compared to the following criteria. The project will be considered to have significant adverse air quality impacts if any one of the thresholds in Table 2-1 are equaled or exceeded.

Construction Air Quality Impacts

Criteria Emissions
Based on a survey of facilities with gaseous- and liquid-fuel engines, SCAQMD staff estimates that 412 engines would require additional source testing g(one additional test every six years) staffing in 2007; 620 engine systems would require minor construction to install infrastructure (sampling ports, platforms, safe access and utilities) and air/fuel ratio controllers by June 2008; 490 engines require installation of CO analyzers and/or NOx-CO CEMS by July 2008; 22 engines would need replacement with electric motors by July 1, 2010; 30 engines would need oxidation catalyst by July 2011; 300 facilities would need modification of three-way catalyst by July 2011; and 78 would need SCR by July 2012. The Landfill Gas to Energy Coalition is concerned that the cost of install in SCR would make flaring an economical alternative to installing SCR. The possibility replacing engines with flares will be examined in the Draft EIR. If it is found that replacing engines with flares is probable, construction emissions from replacement of engines with flares will be analyzed.

Construction or modification of control technologies, engine replacement with electric motor or installation of infrastructure may require cranes, loaders, forklifts, welders and generator sets. Installation of controllers, analyzers, and CEMS systems are likely to require less heavy equipment. All construction would require delivery truck and worker trips. Construction will be evaluated based on the expected number of facilities expected to be affected and the construction schedule. Overlapping construction at the affect facilities may generate significant criteria emissions. Criteria emissions from construction will be analyzed in the Draft EIR.

Toxic Emissions
Diesel exhaust particulate has carcinogenic and chronic non-carcinogenic effects. Diesel exhaust particulate does not have acute health risk values. Carcinogenic health risk is estimated over 70 years for sensitive and residential receptors and 40-years for worker receptors. Construction at any facility is expected to be limited to 32 hours (installation of SCR). Construction for other requirements is expected to last one or two days. Carcinogenic and chronic non-carcinogenic health risks are estimated from annual concentrations. Since the duration of construction for

PAR 1110.2 is much shorter than 70 and 40 years, carcinogenic and chronic non-carcinogenic health risk is expected to be less than significant.

Table 2-1
Air Quality Significance Thresholds

Mass Daily Thresholds		
Pollutant	**Construction**	**Operation**
NOx	100 lbs/day	55 lbs/day
VOC	75 lbs/day	55 lbs/day
PM10	150 lbs/day	150 lbs/day
SOx	150 lbs/day	150 lbs/day
CO	550 lbs/day	550 lbs/day
Lead	3 lbs/day	3 lbs/day
Toxic Air Contaminants (TACs) and Odor Thresholds		
TACs (including carcinogens and non-carcinogens)	Maximum Incremental Cancer Risk ≥ 10 in 1 million Hazard Index ≥ 1.0 (project increment) Hazard Index ≥ 3.0 (facility-wide)	
Odor	Project creates an odor nuisance pursuant to SCAQMD Rule 402	
Ambient Air Quality for Criteria Pollutants [a]		
NO2 1-hour average annual average	SCAQMD is in attainment; project is significant if it causes or contributes to an exceedance of the following attainment standards: 0.25 ppm (state) 0.053 ppm (federal)	
PM10 24-hour average annual geometric average annual arithmetic mean	10.4 μg/m^3 (recommended for construction) [b] & 2.5 μg/m^3 (operation) 1.0 μg/m^3 20 μg/m^3	
Sulfate 24-hour average	1 ug/m^3	
CO 1-hour average 8-hour average	SCAQMD is in attainment; project is significant if it causes or contributes to an exceedance of the following attainment standards: 20 ppm (state) 9.0 ppm (state/federal)	

[a] Ambient air quality thresholds for criteria pollutants based on SCAQMD Rule 1303, Table A-2 unless otherwise stated.
[b] Ambient air quality threshold based on SCAQMD Rule 403.

KEY: lbs/day = pounds per day ppm = parts per million ug/m^3 = microgram per cubic meter ≥ greater than or equal to

Operational Air Quality Impacts

PAR 1110.2 would reduce ozone and particulate emissions from gaseous- and liquid-fueled ICEs. PAR 1110.2 would reduce NOx emission by 5,520 pounds per day, VOC emission by 14,762 pounds per day, and CO emissions by 93,256 pounds per day. Table 2-2 presents estimated emission. Table 2-3 presents estimated emission reductions.

Table 2-2
Estimated Emissions

Description	**NOx, ton/day**	**CO, ton/day**	**VOC, ton/day**
Calculated Baseline	2.84	10.35	1.19
Estimated Actual Baseline (Including Excess Emissions)	4.04	50.24	8.2
Estimated Emissions beginning 6/1/2007	3.98	49.95	8.17
Estimated Emissions beginning 7/1/2008	2.77	10.21	1.18
Estimated Emissions beginning 7/1/2010	2.54	8.15	0.95
Estimated Emissions beginning 7/1/2011	2.34	7.26	0.93
Estimated Emissions beginning 7/1/2012	1.28	3.61	0.82

Table 2-3
Estimated Emission Reductions

Description	**NOx, ton/day**	**CO, ton/day**	**VOC, ton/day**
Estimated Emission Reductions beginning 6/1/2007	0.056	0.30	0.027
Estimated Emission Reductions beginning 7/1/2008	1.21	39.74	6.99
Estimated Emission Reductions beginning 7/1/2010	0.23	2.06	0.23
Estimated Emission Reductions beginning 7/1/2011	0.2	0.89	0.02
Estimated Emission Reductions beginning 7/1/2012	1.06	3.65	0.11
Total	**2.76**	**46.64**	**7.38**

The Landfill Gas to Energy Coalition is concerned that the cost of install in SCR would make flaring an economical alternative to installing SCR. The possibility replacing engines with flares will be examined in the Draft EIR. If it is found that replacing engines with flares is probable, operational emissions from replacement of engines with flares will be analyzed.

Summary

The overall objective of the proposed project is to reduce NOx, VOC and CO emissions from gaseous- and liquid-fueled internal combustion engines. PAR 1110.2 would reduce emissions through engine replacement, control equipment, monitoring equipment and recordkeeping.

Health Risk Analysis

PAR 1110.2 would reduce health risk by reducing VOCs from gaseous- and liquid fueled ICE. Diesel exhaust particulate matter is a known carcinogen with chronic non-carcinogenic effects. Gasoline and natural gas exhaust contains benzene, ethylbenzene, toluene, xylenes, PAHs and other toxics. Therefore, by reducing VOCs, PAR 1110.2 indirectly reduces air toxics, which reduces associated health risks.

PAR 1110.2 includes requirements for the installation of SCR systems, which uses ammonia NOx emissions. A typical SCR system design consists of an ammonia storage tank, ammonia vaporization and injection equipment, a booster fan for the flue gas exhaust, an SCR reactor with catalyst, an exhaust stack plus ancillary electronic instrumentation and operations control equipment. The way an SCR system reduces NOx is by a matrix of nozzles injecting a mixture of ammonia and air directly into the flue gas exhaust stream from the combustion equipment. As this mixture flows into the SCR reactor that is replete with catalyst, the catalyst, ammonia, and oxygen (from the air) in the flue gas exhaust reacts primarily (i.e., selectively) with NO and NO2 to form nitrogen and water in the presence of a catalyst. The amount of ammonia introduced into the SCR system is approximately a one-to-one molar ratio of ammonia to NOx for optimum control efficiency, though the ratio may vary based on equipment-specific NOx reduction requirements. Unreacted ammonia which escapes from the stack is commonly referred to as 'ammonia slip.' Depending on the type of combustion equipment utilizing SCR technology, the typical amount of ammonia slip can vary between five parts per million by volume (ppmv) when the catalyst is fresh and 20 ppmv at the end of the catalyst life, which is generally about five years.

Ammonia is the primary hazardous chemical identified with the proposed project. Ammonia, though not a carcinogen, can have chronic and acute health impacts. Staff estimates approximately 3.64 pounds of ammonia per bhp would be required to reduce NOx. Health risk from ammonia emissions will be evaluated in the Draft EIR.

III.d) Because operational criteria emissions would be reduced, affected facilities are not expected to expose sensitive receptors to substantial operational criteria pollutant concentrations from the implementation of PAR 1110.2. However, because construction criteria pollutant emissions and ammonia emissions during operations may be significant, further evaluation will be presented in the Draft EIR.

III.e) Historically, the SCAQMD has enforced odor nuisance complaints through SCAQMD Rule 402 - Nuisance. Affected facilities are not expected to create objectionable odors affecting a substantial number of people for the following reasons: 1) new installation of compliant ICE systems would be the same as installation of non-compliant ICE systems; and 2) PAR 1110.2 would reduce the emissions and therefore reduce odors; and installation of compliant ICE systems does not require much heavy construction (forklifts and cranes at some facilities), which is often a source of odors from diesel combustion.

Conclusion

Based on the preceding discussion, PAR 1110.2 is expected to reduce NOx, VOC and CO emissions by 5,520, 14,762, and 93,256 pounds per day, respectively, which is an air quality benefit. The proposal has no provision that would cause a violation of any air quality standard or directly contribute to an existing or projected air quality violation. The lower NOx, VOC and CO emissions from gaseous- and liquid ICEs would assist in reducing overall NOx, VOC and CO emissions throughout the district. Thus, PAR 1110.2 is not expected to result in significant criteria pollutant operational adverse air quality impacts.

Construction air quality impacts and ammonia health risk from implementing PAR 1110.2 will be evaluated in the Draft EIR, air quality impacts are not considered to be cumulatively considerable as defined in CEQA Guidelines §15065(c). Therefore, the proposed project is not expected to result in significant averse cumulative impacts for any criteria pollutant.

If construction air quality impacts and ammonia health risk are found to be significant in the Draft EIR, mitigation measures will be identified.

	Potentially Significant Impact	Less Than Significant Impact	No Impact
IV. BIOLOGICAL RESOURCES. Would the project:			
a) Have a substantial adverse effect, either directly or through habitat modifications, on any species identified as a candidate, sensitive, or special status species in local or regional plans, policies, or regulations, or by the California Department of Fish and Game or U.S. Fish and Wildlife Service?	☐	☐	☑
b) Have a substantial adverse effect on any riparian habitat or other sensitive natural community identified in local or regional plans, policies, or regulations, or by the California Department of Fish and Game or U.S. Fish and Wildlife Service?	☐	☐	☑
c) Have a substantial adverse effect on federally protected wetlands as defined by §404 of the Clean Water Act (including, but not limited to, marsh, vernal pool, coastal, etc.) through direct removal, filling, hydrological interruption, or other means?	☐	☐	☑
d) Interfere substantially with the movement of any native resident or migratory fish or wildlife species or with established native resident or migratory wildlife corridors, or impede the use of native wildlife nursery sites?	☐	☐	☑
e) Conflicting with any local policies or ordinances protecting biological resources, such as a tree preservation policy or ordinance?	☐	☐	☑
f) Conflict with the provisions of an adopted Habitat Conservation plan, Natural Community Conservation Plan, or other approved local, regional, or state habitat conservation plan?	☐	☐	☑

Significance Criteria

Impacts on biological resources will be considered significant if any of the following criteria apply:

- The project results in a loss of plant communities or animal habitat considered to be rare, threatened or endangered by federal, state or local agencies.
- The project interferes substantially with the movement of any resident or migratory wildlife species.
- The project adversely affects aquatic communities through construction or operation of the project.

Discussion

PAR 1110.2 would reduce NOx, VOCs and CO from gaseous- and liquid-fueled ICE. Compliance includes retrofit or replacement of equipment to achieve BACT emission levels and improving monitoring, recordkeeping and reporting for better compliance.

IV.a), b), c), & d) PA 1110.2 would not require any new development, but may require minor modifications to buildings or other structures for retrofit or replacement of existing engines; and new, retrofit, or replacement control equipment and monitoring equipment to comply with the proposed rule. PAR 1110.2 may require replacing or altering existing equipment. Any new, replacement or retrofit construction would occur at existing commercial or industrial facilities, so new use designations, including biological habitats, are not expected to be altered by the proposed project. Any construction would occur at affected facilities that are already in existence, which means that Greenfield properties have already been disturbed, but not as a result of PAR 1110.5. Any new operations that must comply with PAR 1110.2 are constructed for business reasons other than to comply with PAR 1110.2. Such projects may or may not have adverse impacts on biological resources. However, these projects would be built regardless of whether or not PAR 1110.2 is in effect.

New, retrofit or replacement construction at existing facilities is expected to occur within the boundaries of the existing facilities. The affected sites are expected have been previously disturbed by site preparation, grating, and construction for the existing gaseous- or liquid-fueled ICE systems. Because of combustion hazards associated with the existing ICE and control systems, it is expect that these areas would be void of biological activity for safety and fire prevention reasons. Therefore, any new, retrofit or replacement construction at existing facilities is not expected to occur in areas that would impact biological resources.

In addition, reducing NOx, VOC, and CO emissions from gaseous- and liquid-fueled ICEs would reduce acid deposition and ozone which impact cultural or historic resources downwind. As a result, PR 1110.2 would not directly or indirectly aversely affect riparian habitat, federally protected wetlands, or migratory corridors. For the same reasons PAR 1110.2 is not expected to adversely affect special status plants, animals, or natural communities.

IV.e) & f) PAR 1110.2 would not conflict with local policies or ordinances protecting biological resources nor local, regional, or state conservation plans because it will only affect industrial or commercial ICE operations. Additionally, PAR 1110.2 will not conflict with any adopted Habitat Conservation Plan, Natural Community Conservation Plan, or any other relevant habitat conservation plan for the same reason.

The SCAQMD, as the Lead Agency for the proposed project, has found that, when considering the record as a whole, there is no evidence that the proposed project will have potential for any new adverse effects on wildlife resources or the habitat upon which wildlife depends. Accordingly, based upon the preceding information, the SCAQMD has, on the basis of substantial evidence, rebutted the presumption of adverse effect contained in §753.5 (d), Title 14 of the California Code of Regulations.

Based upon these considerations, significant adverse biological resources impacts are not anticipated and will not be further analyzed in the Draft EA. Since no significant adverse biological resources impacts were identified, no mitigation measures are necessary or required.

	Potentially Significant Impact	Less Than Significant Impact	No Impact
V. CULTURAL RESOURCES. Would the project:			
a) Cause a substantial adverse change in the significance of a historical resource as defined in §15064.5?	☐	☑	☐
b) Cause a substantial adverse change in the significance of an archaeological resource as defined in §15064.5?	☐	☐	☑
c) Directly or indirectly destroy a unique paleontological resource or site or unique geologic feature?	☐	☐	☑
d) Disturb any human remains, including those interred outside a formal cemeteries?	☐	☐	☑

Significance Criteria

Impacts to cultural resources will be considered significant if:

- The project results in the disturbance of a significant prehistoric or historic archaeological site or a property of historic or cultural significance to a community or ethnic or social group.
- Unique paleontological resources are present that could be disturbed by construction of the proposed project.
- The project would disturb human remains.

PAR 1110.2 would reduce NOx, VOCs and CO from gaseous- and liquid-fueled ICE. Compliance includes retrofit or replacement of equipment to achieve BACT emission levels and improving monitoring, recordkeeping and reporting for better compliance.

V.a) PAR 1110.2 may require replacing or altering existing equipment. Commercial and industrial facilities that operate gaseous- or liquid-fueled ICEs are not expect to be cultural resources. The affected sites are expected have been previously disturbed by site preparation, grating, and construction for the existing gaseous- or liquid-fueled ICE systems.

Significant adverse impacts to cultural resources that are not listed in historical registries or located in historical preservation overlay zones are not expected for the following reasons. Compliant engines, control technology and monitoring equipment are typically prefabricated and dropped into place at the affected site. Therefore, it is not expected that construction or operation would impact historical or cultural resources surround the affected site. As a result, complying with PR 1110.2 would not require demolition, destruction, relocation or alteration of a resource or its immediate surrounding such that the significance of a cultural resource defined in CEQA Guidelines §15064.5 would be impaired. In addition, reducing NOx, VOC emissions from gaseous- and liquid-fueled ICEs would reduce acid deposition and ozone which impact cultural or historic resources downwind.

V, b), c), & d) PAR 1110.2 would not require any new development, but may require minor modifications to buildings or other structures for retrofit or replacement of existing engines; and new, retrofit, or replacement control equipment and monitoring equipment to comply with the proposed rule. New commercial or industrial development may adversely affect cultural resources. However, any new operations that must comply with PAR 1110.2 are constructed for business reasons other than to comply with PAR 1110.2. These development projects would be built regardless of whether or not PAR 1110.2 is in effect.

PAR 1110.2 is not expected to require physical changes to the environment, which may disturb paleontological or archaeological resources. Furthermore, it is envisioned that the areas where existing ICE systems are used are already either devoid of significant cultural resources or whose cultural resources have been previously disturbed.

Based upon these considerations, significant adverse cultural resources impacts are not expected from the implementing PAR 1110.2 and will not be further assessed in the Draft EA. Since no significant cultural resources impacts were identified, no mitigation measures are necessary or required.

	Potentially Significant Impact	Less Than Significant Impact	No Impact
VI. ENERGY. Would the project:			
a) Conflict with adopted energy conservation plans?	☑	☐	☑
b) Result in the need for new or substantially altered power or natural gas utility systems?	☑	☐	☐

		Potentially Significant Impact	Less Than Significant Impact	No Impact
c)	Create any significant effects on local or regional energy supplies and on requirements for additional energy?	☑	☐	☐
d)	Create any significant effects on peak and base period demands for electricity and other forms of energy?	☐	☐	☑
e)	Comply with existing energy standards?	☑	☐	☐

Significance Criteria
Impacts to energy and mineral resources will be considered significant if any of the following criteria are met:

- The project conflicts with adopted energy conservation plans or standards.
- The project results in substantial depletion of existing energy resource supplies.
- An increase in demand for utilities impacts the current capacities of the electric and natural gas utilities.
- The project uses non-renewable resources in a wasteful and/or inefficient manner.

Discussion
PAR 1110.2 would reduce NOx, VOCs and CO from gaseous- and liquid-fueled ICE. Compliance includes retrofit or replacement of equipment to achieve BACT emission levels and improving monitoring, recordkeeping and reporting for better compliance.

PAR 1110.2 would not promote the installation of gaseous- or liquid-fueled engines, but may require the installation or modification of emissions control, sensors, analyzers, CEMS and infrastructure.

VI.a), b), c), d)& e) The Landfill Gas to Energy Coalition is concerned that the cost of the SCR requirement would make flaring gas more economically appealing.

There are several renewable energy goals that have been proposed. The 2002 Renewable Portfolio Standard Program recommended a goal of 20 percent the states electricity mix by 2017. The 2003 Integrated Energy Policy Report recommended achieving 20 percent by 2010. The 2004 Energy Report Update and Energy Action Plan recommended 33 percent by 2020.[12] If landfill gas facility operators would switch from engines to flares because SCR systems would be economically infeasible, then PAR 1110.2 may impact renewable energy plans and existing energy standards..

[12] http://www.energy.ca.gov/renewables/

In addition, if landfill gas facility operators would switch from engines to flares, this may significantly affect power and natural gas utility systems, and local or regional energy supplies at least renewable energy power and natural gas utility systems and supplies.

The Association of California Water Agencies has stated that PAR 1110.2 would severely restrict the ability of water agencies from providing water during power outages. PAR 1110.2 would not affect the water agencies from delivering water during power outages. PAR 1110.2 would not restrict the use of natural gas engines. PAR 1110.2 may require natural gas engines to install new or retrofit monitoring and control equipment, and increase compliance testing on existing engines. The installation of new or retrofit monitoring and control equipment, and increase compliance testing is not expected to impact water supply during power outages. Water districts are expected to provide the appropriate infrastructure to provide water to their customers. Therefore, PAR 1110.2 is not expected to impact water supply during power outages.

As a result, PAR 1110.2 may conflict with energy conservation plans, affect renewable resources result in the need for new or substantially altered power or natural gas systems and supplies. These impact issues will be analyzed in the Draft EA.

VI. The primary effect of implementing PAR 1110.2 is that gaseous- and liquid-fueled ICE would need to be compliant with the proposed rule. Staff estimates that affected commercial and industrial facility operators may require control technology, CO analyzers, AFRC, CEMS or access infrastructure.

Natural Gas Impacts

SCR units would generate a pressure drop though the catalyst and reduce engine efficiency. Non generator engines would require additional natural gas. Based on the pressure drop and reduction of engine efficiency approximately 218 million standard cubic feet (MMscf) of natural gas per year would be required for non generator SCR systems pursuant to PAR 1110.2. Approximately 2.9 MMscf of natural gas would be required for non-generator oxidation catalytic systems. Sixteen two-stroke engines are expected to be replaced with electric motors. Approximately 2,469 MMscf of natural gas per year would be saved by replacing the 22 two-stoke engines with electric motors. Therefore, natural gas usage would be reduced by 2,248 MMscf per year (2,469 – 218 – 2.9 MMscf). Since the total amount of natural gas would be reduced by PAR 1110.2, the proposed project would benefit natural gas reserves in the district. Therefore, PAR 1110.2 is not expected to create any significant effects on local or regional natural gas energy supplies and on requirements for additional energy from natural gas.

Hanover Compressed Natural Gas Company (“Hanover”) operates compressed natural gas (CNG) refueling stations for the Los Angeles Metropolitan Transportation Agency (MTA) transit buses. Hanover has stated that the cost impacts from additional monitoring equipment, change of catalyst, compliance and recordkeeping would be cost prohibitive for their engines. If Hanover operators do replace natural gas engines with electric motors, there will be an additional natural gas benefit. Reduction in natural gas from the conversion of natural gas engines to electric motors was not included in the natural gas analysis.

Table 2-4 presents the maximum natural gas usage by 2012, when the SCR unit and two stroke engine requirements are expected to be completed.

Electrical Impacts
CEMS, controllers, oxidation catalyst and SCR units use electricity for ancillary equipment (e.g., fans, motors, etc.). Electric motors are completely operated by electricity for both ancillary equipment (e.g., fans, motors, etc.) and mechanical work.

Table 2-4
Maximum Natural Gas Usage by 2012

Description	Number of Units	Usage, MMcft/day	Usage, MMcft/year
Oxidation Catalyst Requirement	30	0.0004	2.9
SCR Requirement	8	0.03	218
Electric Motor	24	-0.31	-2,469
Total		**-0.28**	**-2,248**

Electricity Usage from Electric Motors
SCAQMD staff estimates that 22 two stroke engines would be replaced with electric motors. The electric motors would require approximately 234,326 MW-hours per year.

Hanover Compressed Natural Gas Company ("Hanover") has stated that the cost impacts from additional monitoring equipment, change of catalyst, compliance and recordkeeping would be cost prohibitive. If Hanover would replace natural gas engines with electric motors an additional 55 MW-hours/year would be required. Therefore, a total of 289,552 MW-hours per year would be needed. Detailed calculations are presented in Appendix B.

Electricity Usage from Control and Monitoring Devices
CEMS, oxidation and SCR catalysts would require additional electricity. By 2012, approximately 5,123 MW per day would be needed. Detailed calculations are presented in Appendix B.

Table 2-5
Maximum Electricity Usage by 2012

Description	Number of Units	Usage, MW/day	Usage, MW/year
Electric Motor	22	29.3	289,552
CEMS Requirement*	320	0.35	2,837
Oxidation Catalyst Requirement	30	0.0018	14
SCR Requirement	78	0.28	2,272
Total		**30**	**294,674**

* 320 engines, 86 CEMS (all engines at each facility share one CEMS)

Electricity Impacts
According to the 2007 Draft AQMP Program EIR, 120,194 gigawatts-hours per year were available in 2002. The 295 gigawatt-hours per year required by PAR 1110.2 would be less than a percent (0.25 percent) of the available 120,194 gigawatt-hours per year. Therefore, the 295

gigawatt-hours per year would be less than significant and not considered to be wasteful use of an energy resource.

Based upon the above considerations, the proposed project is not expected to use energy in a wasteful manner, would not substantially deplete energy resources.

Based upon the preceding analysis, it is not expected that PAR 1110.2 would create any significant effects on peak and base period demands for electricity and other forms of energy since only minor construction activities (installing or replacing appliances, or rendering appliances inoperable) are anticipated as a result of facilities complying PAR 1110.2.

Therefore, PAR 1110.2 is not expected to significantly affect peak and base period demands for electricity and other forms of energy.

Therefore, PAR 1110.2 is may significantly adversely impact energy conservation plans, affect renewable resources result in the need for new or substantially altered power or natural gas systems and supplies and will be discussed in the Draft EA. If significant impacts are found, mitigation measures will also be analyzed in the Draft EA.

	Potentially Significant Impact	Less Than Significant Impact	No Impact
VII. GEOLOGY AND SOILS. Would the project:			
a) Expose people or structures to potential substantial adverse effects, including the risk of loss, injury, or death involving:	☐	☐	☑
• Rupture of a known earthquake fault, as delineated on the most recent Alquist-Priolo Earthquake Fault Zoning Map issued by the State Geologist for the area or based on other substantial evidence of a known fault?	☐	☐	☑
• Strong seismic ground shaking?	☐	☐	☑
• Seismic–related ground failure, including liquefaction?	☐	☐	☑
• Landslides?	☐	☐	☑
b) Result in substantial soil erosion or the loss of topsoil?	☐	☐	☑

		Potentially Significant Impact	Less Than Significant Impact	No Impact
c)	Be located on a geologic unit or soil that is unstable or that would become unstable as a result of the project, and potentially result in on- or offsite landslide, lateral spreading, subsidence, liquefaction or collapse?	☐	☐	☑
d)	Be located on expansive soil, as defined in Table 18-1-B of the Uniform Building Code (1994), creating substantial risks to life or property?	☐	☐	☑
e)	Have soils incapable of adequately supporting the use of septic tanks or alternative waste water disposal systems where sewers are not available for the disposal of waste water?	☐	☐	☑

Significance Criteria

Impacts on the geological environment will be considered significant if any of the following criteria apply:

- Topographic alterations would result in significant changes, disruptions, displacement, excavation, and compaction or over covering of large amounts of soil.
- Unique geological resources (paleontological resources or unique outcrops) are present that could be disturbed by the construction of the proposed project.
- Exposure of people or structures to major geologic hazards such as earthquake surface rupture, ground shaking, liquefaction or landslides.
- Secondary seismic effects could occur which could damage facility structures, e.g., liquefaction.
- Other geological hazards exist which could adversely affect the facility, e.g., landslides, mudslides.

Discussion

PAR 1110.2 would reduce NOx, VOCs and CO from gaseous- and liquid-fueled ICE. Compliance includes retrofit or replacement of equipment to achieve BACT emission levels and improving monitoring, recordkeeping and reporting for better compliance.

VII.a) Southern California is an area of known seismic activity. Structures must be designed to comply with the Uniform Building Code Zone 4 requirements if they are located in a seismically active area. The local city or county is responsible for assuring that a proposed project complies with the Uniform Building Code as part of the issuance of the building permits and can conduct inspections to ensure compliance. The Uniform Building Code is considered to be a standard safeguard against major structural failures and loss of life. The goal of the code is to provide structures that will: (1) resist minor earthquakes without damage; (2) resist moderate earthquakes without structural damage but with some non-structural damage; and (3) resist major earthquakes without collapse but with some structural and non-structural damage.

The Uniform Building Code bases seismic design on minimum lateral seismic forces ("ground shaking"). The Uniform Building Code requirements operate on the principle that providing appropriate foundations, among other aspects, helps to protect buildings from failure during earthquakes. The basic formulas used for the Uniform Building Code seismic design require determination of the seismic zone and site coefficient, which represent the foundation conditions at the site.

Accordingly, buildings and equipment at existing affected facilities are required to conform to the Uniform Building Code and all other applicable state and local codes in effect at the time they were constructed. PAR 1110.2 would require compliant ICE systems (ICEs, control technology and monitoring equipment). As already noted PAR 1110.2 does not require or promote construction of commercial or industrial land use projects. It is expected that new, retrofitted and replacement ICE systems would be installed according to all applicable state and local codes. As a result, substantial exposure of people or structure to the risk of loss, injury, or death involving seismic-related activities is not anticipated as a result of installing compliant appliances and will not be further analyzed in the Draft EA.

VII.b) PAR 1110.2 would require new, retrofitted and replacement ICE systems. Operators at affected industrial and commercial facilities may retrofit or replace existing ICE systems or add new equipment. It is expected that new, retrofit or replacement equipment are pre-manufactured and dropped in place within existing paved areas at the existing commercial and industrial facilities.

PAR 1110.2 would not require new development. PAR 1110.2 would only affect gaseous- and liquid-fueled ICE systems. There would be no difference in impact to soils from installing a non-compliant versus compliant ICE systems, as new development in the district would continue to be subject to Rule 403-Fugitive Dust. Compliance with Rule 403 would minimize loss of top soil during construction. ICE systems would be built upon concrete foundations which would minimize soil loss.

Installing compliant systems in existing commercial and industrial operation does not require heavy construction that would disturb soil as compliant systems are expected to be pre-manufactured, drop in units. Therefore, no soil disruption from excavation, grading, or filling activities; changes in topography or surface relief features; erosion of beach sand; or changes in existing siltation rates are anticipated from the implementation of PAR 1110.2.

VII.c) & d) Since PAR 1110.2 would primarily affect existing commercial and industrial facilities, it is expected that the soil types present at the affected facilities would not be further susceptible to expansive soils or liquefaction. Furthermore, subsidence is not anticipated to be a problem since no excavation, grading, or filling activities would occur at existing affected facilities because of PAR 1110.2.

PAR 1110.2 would not require or promote new development. At new facilities, the installation of PAR 1110.2 compliant ICE systems would be the similar to installing ICE systems that are compliant with the existing Rule 1110.2. Therefore, installing PAR 1110.2 compliant ICE systems in at new facilities would not generate any additional impacts. Further, the proposed project does not involve drilling or removal of underground products (e.g., water, crude oil, et cetera) that could produce subsidence effects. Additionally, compliant systems installed in new development have no effect on the potential for landsides, lateral spreading subsidence, etc. The new development, not compliance with PAR 1110.2, would be required to undergo a CEQA analysis, which will evaluate potential geological or soil impacts.

Therefore, PAR 1110.2 would not significantly impact soils.

VII.e) The proposed project does not require or involve the installation of septic tanks or alternative wastewater disposal systems. Therefore, no impacts from failures of septic systems related to soils incapable of supporting such systems are anticipated.

Based on the above discussion, the proposed project is not expected to have an adverse impact on geology or soils. Since no significant adverse impacts are anticipated, this environmental topic will not be further analyzed in the draft EA. No mitigation measures are necessary or required.

	Potentially Significant Impact	Less Than Significant Impact	No Impact
VIII. HAZARDS AND HAZARDOUS MATERIALS. Would the project:			
a) Create a significant hazard to the public or the environment through the routine transport, use, disposal of hazardous materials?	☐	☑	☐
b) Create a significant hazard to the public or the environment through reasonably foreseeable upset and accident conditions involving the release of hazardous materials into the environment?	☑	☐	☐
c) Emit hazardous emissions, or handle hazardous or acutely hazardous materials, substances, or waste within one-quarter mile of an existing or proposed school?	☑	☐	☐
d) Be located on a site which is included on a list of hazardous materials sites compiled pursuant to Government Code §65962.5 and, as a result, would create a significant hazard to the public or the environment?	☐	☑	☐

		Potentially Significant Impact	Less Than Significant Impact	No Impact
e)	For a project located within an airport land use plan or, where such a plan has not been adopted, within two miles of a public airport or public use airport, would the project result in a safety hazard for people residing or working in the project area?	☑	☐	☐
f)	For a project within the vicinity of a private airstrip, would the project result in a safety hazard for people residing or working in the project area?	☑	☐	☐
g)	Impair implementation of or physically interfere with an adopted emergency response plan or emergency evacuation plan?	☐	☐	☑
h)	Expose people or structures to a significant risk of loss, injury or death involving wildland fires, including where wildlands are adjacent to urbanized areas or where residences are intermixed with wildlands?	☐	☑	☐
i)	Significantly increased fire hazard in areas with flammable materials?	☐	☐	☑

Significance Criteria

Impacts associated with hazards will be considered significant if any of the following occur:
- Non-compliance with any applicable design code or regulation.
- Non-conformance to National Fire Protection Association standards.
- Non-conformance to regulations or generally accepted industry practices related to operating policy and procedures concerning the design, construction, security, leak detection, spill containment or fire protection.
- Exposure to hazardous chemicals in concentrations equal to or greater than the Emergency Response Planning Guideline (ERPG) 2 levels.

PAR 1110.2 would reduce NOx, VOCs and CO from gaseous- and liquid-fueled ICE. Compliance includes retrofit or replacement of equipment to achieve BACT emission levels and improving monitoring, recordkeeping and reporting for better compliance. The primary effects of the proposed amendments with respect to hazards and hazardous materials are the anticipated overall increase in the amount of ammonia injected into SCR units for controlling NOx emissions from gaseous- and liquid-ICE, the increase of ammonia slip emissions, and the increase of spent catalyst.

Ammonia is the primary hazardous chemical identified with the proposed project. Ammonia, though not a carcinogen, can have chronic and acute health impacts. Therefore, an increase in the use of ammonia in response to the proposed project may increase the current existing risk setting associated with deliveries (i.e., truck and road accidents) and onsite or offsite spills for each of the facilities that currently use or will begin to use ammonia. Exposure to a toxic gas cloud is the potential hazard associated with this type of control equipment.

To minimize hazards associated with ammonia in control systems, the Executive Officer has prohibited the permitting of control technology using anhydrous ammonia. To further minimize the hazards associated with ammonia used in the SCR process, aqueous ammonia, 19 percent by weight, is typically required as a permit condition associated with the installation of SCR equipment for the following reasons: 1) 19 percent aqueous ammonia does not travel as a dense gas like anhydrous ammonia; and, 2) 19 percent aqueous ammonia is not on any acutely hazardous material lists unlike anhydrous ammonia or aqueous ammonia at higher percentages.

Checklist Response Explanation

8. a), b) and c) The proposed project includes the installation of new SCRs and aqueous ammonia storage tanks. The 2004 Final EA for Regulation XX - RECLAIM evaluated the hazards associated with the use, storage, and transport of aqueous ammonia and concluded that no significant impacts were expected, largely due to the requirement to use 19 percent ammonia (which minimizes the impacts of using higher concentrations of ammonia) (SCAQMD, 2004).

Hazards Due to Transport

The 2004 Final EA for Regulation XX - RECLAIM evaluated specific hazards due to transport of aqueous ammonia to several local refineries. It was determined that in the unlikely event that a tanker truck would rupture and release the entire 7,000 gallon capacity of aqueous ammonia, the ammonia solution would have to pool and spread out over a flat surface in order to create sufficient evaporation to produce a significant vapor cloud. For a road accident, the roads are usually graded and channeled to prevent water accumulation and a spill would be channeled to a low spot or drainage system, which would limit the surface area of the spill and the subsequent evaporative emissions. Additionally, the roadside surfaces may not be paved and may absorb some of the spill. In a typical release scenario, because of the characteristics of most roadways, the pooling effect on an impervious surface would not typically occur. As a result, the spilled ammonia would not be expected to evaporate into a toxic cloud at concentrations that could significantly adversely affect residences or other sensitive receptors in the area of the spill (SCAQMD, 2004).

Based of the low probability of an ammonia tanker truck accident with a major release and the potential for exposure to low concentrations, if any, the conclusion of the hazard analysis in the 2004 Final EA was that potential impacts due to accidental release of aqueous ammonia during transportation are less than significant.

It should be noted that this analysis is based on tanker trucks transporting aqueous ammonia in concentrations less than 19 percent by volume, which is consistent with the RECLAIM program. In the 2004 EA, models using aqueous ammonia concentrations of 29.5 percent by volume showed potentially significant hazard impacts, but since Regulation XX will require concentrations of less than 19 percent by volume, consequences of an accidental release during transportation would be less than significant. The permit process would require the transport of aqueous ammonia at concentrations less than 19 percent so the transportation hazards are expected to be less than significant.

Hazards Due to Rupture

Emergency Response Planning Guideline (ERPG) 2 (150 ppm) is the lowest ammonia concentration of interest analyzed in the Draft EA. ERPG-2 concentrations are the maximum airborne concentration below which it is believed nearly all individuals could be exposed for up to one hour without experiencing or developing irreversible or other serious health effects or symptoms that could impair their ability to take protective action. The offsite consequence analysis will also provide the distance to the ERPG-3 concentration (750 ppm). ERPG-3 is the maximum concentration below which nearly all individuals could be exposed for one hour without experiencing or developing life threatening health effects. ERPG-3 concentrations are the maximum airborne concentration below which it is believed that nearly all individuals could be exposed for up to one hour without experiencing or developing life-threatening health effects. "Worst-case" atmospheric conditions (e.g., low winds and stable air) will be used to evaluate whether accidental release concentrations exceed the ERPG-2 and ERPG-3 levels.

SCAQMD staff estimates that the largest ammonia tank installed to comply with PAR 1110.2 would be 5,000 gallons. Storage tanks constructed at affected facilities would be surrounded by secondary containment designs (e.g., dykes, berms, etc.). These same containment facilities would be provided at truck loading racks to contain ammonia in the event of a spill during transfer activities.

The worst-case release scenario would be a catastrophic storage tank failure. The rupture of an ammonia storage tank would release the ammonia into the secondary containment area. Ammonia would then vaporize from the liquid pool in the secondary containment area. Adverse impacts from a catastrophic storage tank failure will be analyzed in the Draft EA.

Affected sites located within one-quarter mile of an existing school site will be disclosed in the Draft EA.

8. d) Adverse impacts to affected hazardous materials sites as defined in Government Code §65962.5 will be estimated and evaluated in the Draft EA.

8. e) and f) Adverse impacts from facilities that use SCR and are located within an airport land use plan or within two miles of a public or private use airport will be evaluated in the Draft EA

8. g) The proposed project modifications are located within the existing operating portions of affected facilities. The proposed projects are not expected to alter the routes employees would take to evacuate the site, as the evacuation routes generally direct employees to locations outside of the main operating portions of the facilities. The existing emergency response plan is not expected to require modifications due to the proposed projects. No significant adverse impacts to emergency response or evacuation plans are expected.

8. h) Since existing ICE systems are operating the proposed project would not increase the existing risk of fire hazards in areas with flammable brush, grass, or trees. SCAQMD staff does not expect facilities to alter the type or amount of fuel used when replacing or retrofitting engines. None of the control technologies or monitoring equipment is expected to use flammable materials. In addition, the proposed projects are located in urbanized, industrial areas and no wildlands are expected to be located in the immediate or surrounding areas. Also, no substantial or native vegetation is expected to exist within the operational portions of any of the affected facilities, since existing ICE systems are operating at these facilities. For these reasons, the proposed projects would not expose people or structures to wildland fires. Therefore, no potential significant adverse impacts resulting from wildland fire hazards are expected from the proposed projects.

8. i) None of the control technologies or monitoring equipment is expected to use flammable materials (aqueous ammonia is not flammable). PAR 1110.2 would not require a change in operation, fuels consumed or stored; therefore, the proposed projects will not increase the potential for fire hazards at the affected facilities.

Conclusion
Ammonia is the only hazardous material associated with PAR 1110.2 that was identified. The effects of an accidental release of ammonia during transported from the proposed projects were not determined to be significant. The effects of an accidental release of ammonia from a catastrophic storage tank failure will be analyzed in the Draft EA. The location of ammonia storage tanks proposed near schools, hazardous material sites, and airport and airstrips will be disclosed in the Draft EA.

		Potentially Significant Impact	Less Than Significant Impact	No Impact
IX.	**HYDROLOGY AND WATER QUALITY.** Would the project:			
a)	Violate any water quality standards or waste discharge requirements?	☐	☐	☑
b)	Substantially deplete groundwater supplies or interfere substantially with groundwater recharge such that there would be a net deficit in aquifer volume or a lowering of the local groundwater table level (e.g. the production rate of pre-existing nearby wells would drop to a level which would not support existing land uses or planned uses for which permits have been granted)?	☐	☐	☑

		Potentially Significant Impact	Less Than Significant Impact	No Impact
c)	Substantially alter the existing drainage pattern of the site or area, including through alteration of the course of a stream or river, or substantially increase the rate or amount of surface runoff in a manner that would result in flooding on- or offsite?	☐	☐	☑
d)	Create or contribute runoff water which would exceed the capacity of existing or planned stormwater drainage systems or provide substantial additional sources of polluted runoff?	☐	☐	☑
e)	Otherwise substantially degrade water quality?	☐	☐	☑
f)	Place housing within a 100-year flood hazard area as mapped on a federal Flood Hazard Boundary or Flood Insurance Rate Map or other flood hazard delineation map?	☐	☐	☑
g)	Place within a 100-year flood hazard area structures which would impede or redirect flood flaws?	☐	☐	☑
h)	Expose people or structures to a significant risk of loss, injury or death involving flooding, including flooding as a result of the failure of a levee or dam?	☐	☐	☑
i)	Inundation by seiche, tsunami, or mudflow?	☐	☐	☑
j)	Exceed wastewater treatment requirements of the applicable Regional Water Quality Control Board?	☐	☐	☑
k)	Require or result in the construction of new water or wastewater treatment facilities or expansion of existing facilities, the construction of which could cause significant environmental effects?	☐	☐	☑
l)	Require or result in the construction of new storm water drainage facilities or expansion of existing facilities, the construction of which could cause significant environmental effects?	☐	☐	☑

m)	Have sufficient water supplies available to serve the project from existing entitlements and resources, or are new or expanded entitlements needed?	☐	☐	☑
n)	Require in a determination by the wastewater treatment provider which serves or may serve the project that it has adequate capacity to serve the project's projected demand in addition to the provider's existing commitments?	☐	☐	☑

Significance Criteria
Potential impacts on water resources will be considered significant if any of the following criteria apply:

Water Quality:
- The project will cause degradation or depletion of ground water resources substantially affecting current or future uses.
- The project will cause the degradation of surface water substantially affecting current or future uses.
- The project will result in a violation of National Pollutant Discharge Elimination System (NPDES) permit requirements.
- The capacities of existing or proposed wastewater treatment facilities and the sanitary sewer system are not sufficient to meet the needs of the project.
- The project results in substantial increases in the area of impervious surfaces, such that interference with groundwater recharge efforts occurs.
- The project results in alterations to the course or flow of floodwaters.

Water Demand:
- The existing water supply does not have the capacity to meet the increased demands of the project, or the project would use a substantial amount of potable water.
- The project increases demand for water by more than five million gallons per day.

Discussion
PAR 1110.2 would reduce NOx, VOCs and CO from gaseous- and liquid-fueled ICE. Compliance includes retrofit or replacement of equipment to achieve BACT emission levels and improving monitoring, recordkeeping and reporting for better compliance.

IX.a), e), f), j), k), & l) PAR 1110.2 would require the replacement or retrofit of ICE systems. PAR 1110.2 has no provision that would require the use of water or the disposal of wastewater, because compliant ICEs do not use water for any reason. Therefore, PAR 1110.2 would not cause the construction of additional water resource facilities, the need for new or expanded water entitlements, or an alteration of drainage patterns. Since it does not require water, the project would not substantially deplete groundwater supplies or interfere substantially with groundwater recharge.

ICE systems do not generate wastewater and, therefore, would not create or contribute to runoff water. ICE systems are housed within structures that would protect them from exposure to and contaminating stormwater. ICE systems that are used outdoors are typically protected from weather, especially rain and would not be expected to contaminate stormwater in any way. Since both compliant and non-compliant ICE systems are typically enclosed systems, ICE systems are not expected to contaminate rainwater. Therefore, PAR 1110.2 would not create or contribute runoff water that would exceed the capacity of existing or planned stormwater drainage systems or provide substantial additional sources of polluted runoff.

In addition, the proposed rule is not expected to require additional wastewater disposal capacity, violate any water quality standard or wastewater discharge requirements, or otherwise substantially degrade water quality.

IX.b), & n) PAR 1110.2 is not expected to substantially deplete groundwater supplies or interfere with groundwater recharge such that there would be a net deficit in aquifer volume or a lowering of the local groundwater table level. PAR 1110.2 would not increase demand for water from existing entitlements and resources, and will not require new or expanded entitlements because compliant devices do not use water for any reason. Therefore, no water demand impacts are expected as the result of implementing the proposed amendments.

IX.c) & d) PAR 1110.2 may include minor construction activities to retrofit or replace ICE systems within new or existing affected facilities, installation of replacement or retrofit equipment is not expected to require earthmoving or excavation so not soil disturbance would occur as a results of implementing PAR 1110.2. As result, no changes to storm water runoff, drainage patterns, groundwater characteristics, or flow are expected. Therefore, potential adverse impacts to drainage patterns, etc., are not expected as a result of implementing PAR 1110.2.

IX.g), h) & i) The project will not require or induce construction of new housing or contribute to the construction of new building structures other than retrofit or replacement of equipment within existing affected facilities. PAR 1110.2 may affect ICE systems at new facilities, but would not require any new facilities. Therefore, PAR 1110.2 is not expected to generate construction of any new structures in 100-year flood areas as mapped on a federal Flood Hazard Boundary or Flood Insurance Rate Map or other flood delineation map. As a result, PAR 1110.2 is not expected to expose people or structures to new significant flooding risks. Modification of existing systems in existing affected facilities would not affect any existing risks from flood, inundation, etc. Consequently, PAR 1110.2 would not affect in any way any potential flood hazards inundation by seiche, tsunami, or mud flow that may already exist relative to existing facilities.

IX.m) PAR 1110.2 will not demand for water supplies, since only minor construction activities (retrofit or replacement of existing equipment) are expected to occur within affected facilities. Similarly, compliant appliances do not use water for any purpose; therefore, no storm water discharge supply facilities or modifications to existing facilities would be required due to the implementation of PAR 1110.2. Accordingly, PAR 1110.2is not expected to generate significant adverse impacts relative to construction of new storm water drainage facilities.

Based upon the above considerations, significant hydrology and water quality impacts are not expected from the implementation of PAR 1110.2 and will not be further analyzed in the Draft EA.

Since no significant hydrology and water quality impacts were identified, no mitigation measures are necessary or required.

		Potentially Significant Impact	Less Than Significant Impact	No Impact
X.	**LAND USE AND PLANNING.** Would the project:			
a)	Physically divide an established community?	☐	☐	☑
b)	Conflict with any applicable land use plan, policy, or regulation of an agency with jurisdiction over the project (including, but not limited to the general plan, specific plan, local coastal program or zoning ordinance) adopted for the purpose of avoiding or mitigating an environmental effect?	☐	☐	☑
c)	Conflict with any applicable habitat conservation or natural community conservation plan?	☐	☐	☑

Significance Criteria

Land use and planning impacts will be considered significant if the project conflicts with the land use and zoning designations established by local jurisdictions.

Discussion

X.a) The proposed project would require retrofit or replacement of existing ICE systems and installation of compliant systems at new affected facilities. PAR 1110.2 does not require any new development, but would require installation of compliant systems installed in new development. At existing facilities, PAR 1110.2 would impact the ope1110.2 does not include any components that would require physically dividing an established community.

X.b) & c) There are no provisions in PAR 1110.2 that would affect land use plans, policies, or regulations. Land use and other planning considerations are determined by local governments and no land use or planning requirements will be altered by regulating NOx, VOC and CO emissions from ICE systems. Therefore, PAR 1110.2 would not affect in any way habitat conservation or natural community conservation plans, agricultural resources or operations, and would not create divisions in any existing communities. Therefore, present or planned land uses in the region will not be significantly adversely affected as a result of the proposed rule

Based upon these considerations, significant land use and planning impacts are not expected from the implementation of PAR 1110.2 and will not be further analyzed in the Draft EA. Since no significant land use and planning impacts were identified, no mitigation measures are necessary or required.

	Potentially Significant Impact	Less Than Significant Impact	No Impact
XI. MINERAL RESOURCES. Would the project:			
a) Result in the loss of availability of a known mineral resource that would be of value to the region and the residents of the state?	☐	☐	☑
b) Result in the loss of availability of a locally-important mineral resource recovery site delineated on a local general plan, specific plan or other land use plan?	☐	☐	☑

Significance Criteria

Project-related impacts on mineral resources will be considered significant if any of the following conditions are met:

- The project would result in the loss of availability of a known mineral resource that would be of value to the region and the residents of the state.
- The proposed project results in the loss of availability of a locally-important mineral resource recovery site delineated on a local general plan, specific plan or other land use plan.

Discussion

XI.a) & b) There are no provisions in PAR 1110.2 that would result in the loss of availability of a known mineral resource of value to the region and the residents of the state, or of a locally-important mineral resource recovery site delineated on a local general plan, specific plan or other land use plan because compliant appliances typically do not require mineral resources such as sand, gravel, etc..

Based upon the above considerations, significant mineral resources impacts are not expected from the implementation of PAR 1110.2 and will not be further analyzed in the Draft EA. Since no significant mineral resources impacts were identified, no mitigation measures are necessary or required.

	Potentially Significant Impact	Less Than Significant Impact	No Impact
XII. NOISE. Would the project result in:			
a) Exposure of persons to or generation of noise levels in excess of standards established in the local general plan or noise ordinance, or applicable standards of other agencies?	☐	☐	☑
b) Exposure of persons to or generation of excessive groundborne vibration or groundborne noise levels?	☐	☐	☑
c) A substantial permanent increase in ambient noise levels in the project vicinity above levels existing without the project?	☐	☐	☑
d) A substantial temporary or periodic increase in ambient noise levels in the project vicinity above levels existing without the project?	☐	☐	☑
e) For a project located within an airport land use plan or, where such a plan has not been adopted, within two miles of a public airport or public use airport, would the project expose people residing or working in the project area to excessive noise levels?	☐	☐	☑
f) For a project within the vicinity of a private airship, would the project expose people residing or working in the project area to excessive noise levels?	☐	☐	☑

Significance Criteria

Impacts on noise will be considered significant if:

- Construction noise levels exceed the local noise ordinances or, if the noise threshold is currently exceeded, project noise sources increase ambient noise levels by more than three decibels (dBA) at the site boundary. Construction noise levels will be considered significant if they exceed federal Occupational Safety and Health Administration (OSHA) noise standards for workers.
- The proposed project operational noise levels exceed any of the local noise ordinances at the site boundary or, if the noise threshold is currently exceeded, project noise sources increase ambient noise levels by more than three dBA at the site boundary.

Discussion

XII.a) PAR 1110.2 would require retrofit and replacement of ICE systems in existing and installation of compliant ICE systems in new affected facilities. Since installation or replacement of ICEs is expected to be comprised of pre-fabricated equipment that would not require much heavy duty construction equipment, noise impacts during replacement would be minimal. Most facilities are not expected to need heavy construction equipment. Large ICE systems may require a crane or lift to install replacement ICE and control equipment or retrofit equipment. However, facilities that use large ICEs, typically have diesel truck, industrial equipment and/or on-site mobile equipment that generate comparable noise. Therefore, the operation of an additional crane or lift is not expected to be significant. The retrofit or replacement systems are not expected to generate more noise than existing systems. New ICE systems at new facilities are not expected to be louder than currently compliant systems that would be required if PAR 1110.2 is not adopted. In addition, building codes typically include set backs for ICE systems from the property line, noise from these systems indoors and outdoors are expected to be limited to acceptable levels by the building permit process. Thus, the proposed project is not expected to expose persons to the generation of excessive noise levels above current facility levels. It is expected that any facility affected by PAR 1110.2 would comply with all existing local noise control laws or ordinances.

In commercial environments Occupational Safety and Health Administration (OSHA) and California-OSHA have established noise standards to protect worker health. It is expected that operators at affected facilities would continue complying with applicable noise standards, which would limit noise impacts to workers, patrons and neighbors.

XII.b) PAR 1110.2 is not anticipated to expose people to or generate excessive groundborne vibration or groundborne noise levels since only minor construction activities are expected to occur at the existing facilities and compliant equipment are not expected to involve, in any way, equipment that generates vibrations over existing equipment.

XII.c) A permanent increase in ambient noise levels at the affected facilities above existing levels as a result of implementing the proposed project is unlikely to occur because for most affected facilities similar equipment would be installed as part of implementing PAR 1110.2. The existing noise levels are unlikely to change and raise ambient noise levels in the vicinities of the existing facilities to above a level of significance, because neither non-compliant nor compliant ICEs are expected to general comparable levels of noise.

XII.d) No increase in periodic or temporary ambient noise levels in the vicinity of affected facilities above levels existing prior to PAR 1110.2 is anticipated because the proposed project would require only minor construction (installation or replacement of ICE systems) activities that would not require heavy equipment besides cranes or lifts. As indicated earlier, operational noise levels are expected to be equivalent to existing noise levels.

XII.e) & f) Implementation of PAR 1110.2 would generally consist of improvements within the existing facilities. Minor construction may be required to install or replace appliances. Even if an affected facility is located near a public/private airport, there are no new noise impacts expected from any of the existing facilities, ether during construction or operation, as a result of complying with the proposed project. Thus, PAR 1110.2 is not expected to expose people residing or working in the vicinities of public airports to excessive noise levels.

Based upon these considerations, significant noise impacts are not expected from the implementation of PAR 1110.2 and are not further evaluated in the Draft EA. Since no significant noise impacts were identified, no mitigation measures are necessary or required.

	Potentially Significant Impact	Less Than Significant Impact	No Impact
XIII. POPULATION AND HOUSING. Would the project:			
a) Induce substantial growth in an area either directly (for example, by proposing new homes and businesses) or indirectly (e.g. through extension of roads or other infrastructure)?	☐	☐	☑
b) Displace substantial numbers of existing housing, necessitating the construction of replacement housing elsewhere?	☐	☐	☑
c) Displace substantial numbers of people, necessitating the construction of replacement housing elsewhere?	☐	☐	☑

Significance Criteria

Impacts of the proposed project on population and housing will be considered significant if the following criteria are exceeded:

- The demand for temporary or permanent housing exceeds the existing supply.
- The proposed project produces additional population, housing or employment inconsistent with adopted plans either in terms of overall amount or location.

Discussion

XIII.a) The proposed project is not anticipated to generate any significant effects, either direct or indirect, on the district's population or population distribution as no additional workers are anticipated to be required to comply with the proposed amendments. Human population within the jurisdiction of the SCAQMD is anticipated to grow regardless of implementing PAR 1110.2. It is expected that any construction activities at affected facilities would use construction workers from the local labor pool in southern California. As such, PAR 1110.2 will not result in changes in population densities or induce significant growth in population.

XIII.b) & c) Because the proposed project affects ICE systems at commercial and industrial facilities, PAR 1110.2 is not expected to result in the creation of any industry that would affect population growth, directly or indirectly, induce the construction of single- or multiple-family units, or require the displacement of people elsewhere.

Based upon these considerations, significant population and housing impacts are not expected from the implementation of PAR 1110.2 and are not further evaluated in the Draft EA. Since no significant population and housing impacts were identified, no mitigation measures are necessary or required.

	Potentially Significant Impact	Less Than Significant Impact	No Impact
XIV. PUBLIC SERVICES. Would the proposal result in substantial adverse physical impacts associated with the provision of new or physically altered governmental facilities, need for new or physically altered government facilities, the construction of which could cause significant environmental impacts, in order to maintain acceptable service ratios, response times or other performance objectives for any of the following public services:			
a) Fire protection?	☐	☑	☐
b) Police protection?	☐	☐	☑
c) Schools?	☐	☐	☑
d) Parks?	☐	☐	☑
e) Other public facilities?	☐	☑	☐

Significance Criteria

Impacts on public services will be considered significant if the project results in substantial adverse physical impacts associated with the provision of new or physically altered governmental facilities, or the need for new or physically altered government facilities, the construction of which could cause significant environmental impacts, in order to maintain acceptable service ratios, response time or other performance objectives.

Discussion

XIV.a) & b) The replacement or modification of ICE systems is not expected to increase the chances for fires or explosions requiring a response from local fire departments. As shown in the Section VIII - Hazards and Hazardous Material section of the Draft EA, the use of compliant ICE systems is not expected to generate significant explosion or fire hazard impacts.

The Association of California Water Agencies (ACWA) has implied that PAR 1110.2 would require the removal of natural gas engines that would hinder the ability of water agencies to supply water to fight fires. PAR 1110.2 would not require water agencies to remove natural gas engines. PAR 1110.2 may require additional or retrofit monitoring, control equipment, and recordkeeping. The additional retrofit monitoring, control equipment and recordkeeping is not expected to hinder the delivery of water to fire fighters. Therefore, PAR 1110.2 is not expected to have a significant impact on fire fighters.

In addition, SCAQMD staff has reviewed a list of public water agencies that are members of the ACWA. Some of the largest public water agencies Los Angeles Department of Water and Power (LA DWP), Metropolitan Water District (MWD) of Southern California, MWD of Orange County, and Orange County Water District do not have natural gas engines. There are several public water agencies located in areas susceptible to wildfires that do not have natural gas engines: Elsinore Valley MWD, Idywild Water District (WD), Lake Hemet MWD, etc. Since there are large water districts and water districts in areas susceptible to wildfires that are able to support fire fighters without natural gas engines, it is expected that facilities that have natural gas engines would comply with PAR 1110.2 or develop means used by water districts that do not use natural gas engines to fight wild fires. Therefore, it is not expected that PAR 1110.2 would significantly affect wildfire fighting efforts.

PAR 1110.2 is not expected to have any adverse effects on local police departments for the following reasons. Police would be required to respond to accidental releases of hazardous materials during transport. Since hazards impacts from implementing PAR 1110.2 were concluded to be less than significant, potential impacts to local police departments are also expected to be less than significant.

XIV.c) & d) As indicated in discussion under item XIII. Population and Housing, implementing PAR 1110.2 would not induce population growth or dispersion during either construction or operation. Therefore, with no increase in local population anticipated, additional demand for new or expanded schools or parks is not anticipated. As a result, no significant adverse impacts are expected to local schools or parks.

XIV.e) Besides building permits, there is no other need for government services. The proposal would not result in the need for new or physically altered government facilities in order to maintain acceptable service ratios, response times, or other performance objectives. There will be no increase in population and, as a result of implementing; therefore, no need for physically altered government facilities.

Based upon these considerations, significant public services impacts are not expected from the implementation of PAR 1110.2 and are not further evaluated in the Draft EA. Since no significant public services impacts were identified, no mitigation measures are necessary or required.

	Potentially Significant Impact	Less Than Significant Impact	No Impact
XV. RECREATION.			
a) Would the project increase the use of existing neighborhood and regional parks or other recreational facilities such that substantial physical deterioration of the facility would occur or be accelerated?	☐	☐	☑
b) Does the project include recreational facilities or require the construction or expansion of recreational facilities that might have an adverse physical effect on the environment?	☐	☐	☑

Significance Criteria

Impacts to recreation will be considered significant if:

- The project results in an increased demand for neighborhood or regional parks or other recreational facilities.
- The project adversely affects existing recreational opportunities.

Discussion

XV.a) & b) As discussed under "Land Use and Planning" above, there are no provisions in the PAR 1110.2 that would affect land use plans, policies, or regulations. Land use and other planning considerations are determined by local governments and no land use or planning requirements will be altered by the changes proposed in PAR 1110.2. The proposed project would not increase the demand for or use of existing neighborhood and regional parks or other recreational facilities or require the construction of new or expansion of existing recreational facilities that might have an adverse physical effect on the environment because it will not directly or indirectly increase or redistribute population.

Based upon these considerations, significant recreation impacts are not expected from the implementation of PAR 1110.2 and are not further evaluated in the Draft EA. Since no significant recreation impacts were identified, no mitigation measures are necessary or required.

	Potentially Significant Impact	Less Than Significant Impact	No Impact
XVI. SOLID/HAZARDOUS WASTE. Would the project:			
a) Be served by a landfill with sufficient permitted capacity to accommodate the project's solid waste disposal needs?	☐	☑	☐
b) Comply with federal, state, and local statutes and regulations related to solid and hazardous waste?	☐	☐	☑

Significance Criteria

The proposed project impacts on solid/hazardous waste will be considered significant if the following occurs:

- The generation and disposal of hazardous and non-hazardous waste exceeds the capacity of designated landfills.
-

Discussion

XVI.a) PAR 1110.2 would generate both solid and hazardous waste. PAR 1110.2 may necessitate the replacement of two-stroke ICEs with electric motors. Existing ICES are not expected to be classified as hazardous waste. Therefore, the disposal of existing ICEs is expected to be categorized as solid waste.

PAR 1110.2 may require the upgrade of existing catalyst, and installation of new oxidation catalyst systems and SCR systems. Metals used in catalyst are generally recovered because they are made of precious and valuable mettles (e.g., platinum and palladium). Metals can be recovered from approximately 60 percent of the spent catalyst generated from the operation of catalytic oxidizers.[13] None of the SCR catalyst is recycled, because it does not contain precious metals. Catalyst from control technology is classified as hazardous waste. These metals could then be recycled. The remaining material would likely need to be disposed of at a hazardous waste landfill.

Solid Waste

The Final Program Environmental Impact Report for the 2003 AQMP states that the daily landfill capacity for Los Angeles, Orange, Riverside and San Bernardino Counties is 101,344 tons per day (Table 3.5-1, page 3.5-2). In a worst-case scenario, it is estimated that as much as, 151 tons of the material from the replacement of two-stoke engines with electric motors would eventually be sent to landfill by July 1, 2007. Since cities and landfills are required to divert recyclable material to recycling center a large amount of the recyclable from the engines should get recycled. The total waste from PAR 1110.2 would be less than one percent of the total daily

[13] SCAQMD, 2003 Final AQMP Program EIR, 2003.

capacity. Therefore, the increase in solid waste that would be generated from the proposed project is less than significant. Detailed calculations can be found in Appendix B.

Hazardous Waste

Approximately 120 tons of catalyst will be installed pursuant to PAR 1110.2. Catalysts have a lifespan of approximately three years. Assuming that a third of the catalyst is replaced every year approximately 14.6 tons of catalyst will be disposed per year of and 0.7 ton per year will be recycled. Detailed calculations can be found in Appendix B.

Depending on its actual waste designation, spent catalysts would likely be disposed of in a Class II landfill or a Class III landfill that is fitted with liners. According to the Program EIR for the 2003 AQMP (SCAQMD, 2003), total Class III landfill waste disposal capacity in the district is approximately 101,340 tons per day, many of which have liners and can handle Class II and Class III wastes. The initial disposal of two tons of existing catalyst and fifteen tons per year of catalyst is less than one percent of 101,340 tons per day. Therefore disposal of catalyst is not considered significant.

XVI.b) Most cities have solid and hazardous waste disposal requirements. Many cities require that scrap metal be recycled. In addition, because of the value of scrap metal, contractors will recycle scrap metal. Contractors are expected to adherence to the applicable federal, state and local regulatory requirements for the disposal of solid waste.

Based on these considerations, PAR 1110.2 is not expected to significantly increase the volume of solid or hazardous wastes disposed at existing municipal or hazardous waste disposal facilities or require additional waste disposal capacity. Further, implementing PAR 1110.2 is not expected to interfere with any affected facility's ability to comply with applicable local, state, or federal waste disposal regulations. Since no solid/hazardous waste impacts were identified, no mitigation measures are necessary or required.

	Potentially Significant Impact	Less Than Significant Impact	No Impact
XVII. TRANSPORTATION/TRAFFIC. Would the project:			
a) Cause an increase in traffic which is substantial in relation to the existing traffic load and capacity of the street system (i.e., result in a substantial increase in either the number of vehicle trips, the volume to capacity ratio on roads, or congestion at intersections)?	☐	☐	☑

		Potentially Significant Impact	Less Than Significant Impact	No Impact
b)	Exceed, either individually or cumulatively, a level of service standard established by the county congestion management agency for designated roads or highways?	☐	☐	☑
c)	Result in a change in air traffic patterns, including either an increase in traffic levels or a change in location that results in substantial safety risks?	☐	☐	☑
d)	Substantially increase hazards due to a design feature (e.g. sharp curves or dangerous intersections) or incompatible uses (e.g. farm equipment)?	☐	☐	☑
e)	Result in inadequate emergency access or?	☐	☐	☑
f)	Result in inadequate parking capacity?	☐	☐	☑
g)	Conflict with adopted policies, plans, or programs supporting alternative transportation (e.g. bus turnouts, bicycle racks)?	☐	☐	☑

Significance Criteria

Impacts on transportation/traffic will be considered significant if any of the following criteria apply:

- Peak period levels on major arterials are disrupted to a point where level of service (LOS) is reduced to D, E or F for more than one month.
- An intersection's volume to capacity ratio increase by 0.02 (two percent) or more when the LOS is already D, E or F.
- A major roadway is closed to all through traffic, and no alternate route is available.
- There is an increase in traffic that is substantial in relation to the existing traffic load and capacity of the street system.
- The demand for parking facilities is substantially increased.
- Water borne, rail car or air traffic is substantially altered.
- Traffic hazards to motor vehicles, bicyclists or pedestrians are substantially increased.
- The need for more than 350 employees
- An increase in heavy-duty transport truck traffic to and/or from the facility by more than 350 truck round trips per day
- Increase customer traffic by more than 700 visits per day.

Discussion

XVII.a) & b) PAR 1110.2 has a variety of requirements that with compliance dates from 2007 to 20012. Most of the construction would occur within the first two years. Based on a survey of facilities with gaseous- and liquid-fuel engines, SCAQMD staff estimates that 435 engines would require source test in 2007; 528 engine systems would require minor construction to install infrastructure (sampling ports, platforms, safe access and utilities) and air/fuel ratio controllers by June 2008; 742 engines require installation of CO analyzers and/or NOx-CO CEMS by July 2008; 517 engines would need replacement with electric motors by July 1, 2010; 298 engines would need oxidation catalyst or modification of oxidation catalyst by July 2011; and 154 facilities would need oxidation catalyst, modification of oxidation catalyst or SCR. Construction or modification of control technologies, engine replacement with electric motor or installation of infrastructure may require cranes, loaders, forklifts, welders and generator sets. Installation of controllers, analyzers, and CEMS systems are likely to require less heavy equipment. All construction would require delivery truck and worker trips. Based on the above, SCAQMD staff assumes that construction would occur at approximately 15 facilities per day beginning in 2007 through 2008. Between 2009 to 2012, construction would occur at one or two facilities per day. Based on construction at 15 facilities per day, approximately 50 delivery or haul truck trips and 75 worker trips would be required. Since these construction work trips would be spread through the district, these additional construction work trips would not impact transportation or traffic significantly.

During operation, one ammonia delivery per quarter may be required for 76 SCR systems. One trip would be required at each facility every six years for additional source testing. One trip would be required every three years at 11 facilities to replace oxidation catalyst. These additional operational diesel truck trips would not impact transportation or traffic significantly.

XVII.c) PAR 1110.2 would require the replacement or retrofit of existing ICE systems and the installation of compliant ICE systems at new facilities. The stack heights for compliant ICE systems are not expected to be significantly higher than existing systems. Building codes should prevent stacks from adversely affect air traffic patterns. Further, PAR 1110.2 would not affect in any way air traffic in the region because ICE systems or components are not expected to be transported by plane to any appreciable extent.

XVII.d) Since PAR 1110.2 affects ICE systems, no offsite modifications to roadways are anticipated for the proposed project that would result in an additional design hazard or incompatible uses.

XVII.e) Since PAR 1110.2 affects ICE systems, no changes are expected to emergency access at or in the vicinity of the affected facilities. The proposed project is not expected to adversely impact emergency access because it primarily requires replacement of non-compliant appliances with compliant appliances.

XVII.f) Since PAR 1110.2 affects ICE systems, no changes are expected to the parking capacity at or in the vicinity of the affected facilities. PAR 1110.2 is not expected to require additional workers, so additional parking capacity will not be required. Therefore, the project is not expected to adversely impact on- or off-site parking capacity.

XVII.g) Since PAR 1110.2 affects ICE systems, the implementation of PAR 1110.2 would not result in conflicts with alternative transportation, such as bus turnouts, bicycle racks, et cetera.

Based upon these considerations, PAR 1110.2 is not expected to generate significant adverse transportation/traffic impacts and, therefore, this topic will not be considered further. Since no significant transportation/traffic impacts were identified, no mitigation measures are necessary or required.

	Potentially Significant Impact	Less Than Significant Impact	No Impact
XVIII. MANDATORY FINDINGS OF SIGNIFICANCE.			
a) Does the project have the potential to degrade the quality of the environment, substantially reduce the habitat of a fish or wildlife species, cause a fish or wildlife population to drop below self-sustaining levels, threaten to eliminate a plant or animal community, reduce the number or restrict the range of a rare or endangered plant or animal or eliminate important examples of the major periods of California history or prehistory?	☑	☐	☐
b) Does the project have impacts that are individually limited, but cumulatively considerable? ("Cumulatively considerable" means that the incremental effects of a project are considerable when viewed in connection with the effects of past projects, the effects of other current projects, and the effects of probable future projects)	☐	☐	☑
c) Does the project have environmental effects that will cause substantial adverse effects on human beings, either directly or indirectly?	☑	☐	☐

XVIII.a) As discussed in the "Biological Resources" section, PAR 1110.2 is not expected to significantly adversely affect plant or animal species or the habitat on which they rely because PAR 1110.2 is expected to affect equipment or processes located at existing commercial or industrial facilities, which are typically areas that have already been greatly disturbed and that currently do not support such habitats. Additionally, PAR 1110.2 does not require or induce construction of any new land use projects that could affect biological resources. Construction of new land use projects would be done for reasons unrelated to PAR 1110.2.

XVIII.b) Based on the foregoing analyses, since PAR 1110.2 may generate any project-specific adverse significant environmental impacts for air quality, energy and hazards and hazardous materials. If significant adverse project-specific impacts are generated by PAR 1110.2, the project is expected to be cumulatively significant for those environmental topics. If PAR 1110.2

is not determined to be significant for adverse project-specific impacts, then it is not expected to cause cumulative impacts in conjunction with other projects that may occur concurrently with or subsequent to the proposed project. Related projects to the currently proposed project include existing and proposed rules and regulations, as well as AQMP control measures. The environmental topics checked 'No Impact' (e.g., aesthetics, agriculture resources, biological resources, cultural resources, geology and soils, hydrology and water quality, land use and planning, mineral resources, noise, population and housing, public services, recreation, and transportation and traffic) would not be expected to make any contribution to potential cumulative impacts whatsoever. For the environmental topic checked 'Less than Significant Impact' (e.g., solid/hazardous waste), the analysis indicated that project impacts would not exceed any project-specific significance thresholds. This conclusion is based on the fact that the analyses for each of these environmental areas concluded that the incremental effects of the proposed project would be minor and, therefore, not considered to be cumulatively considerable.

XVIII.c) Based on the foregoing analyses, PAR 1110.2 may cause significant adverse effects on human beings. The Draft EA will analyze air quality, energy and hazards and hazardous material impacts expected from the implementation of PAR 1110.2. Based on the preceding analyses, no significant adverse impacts to aesthetics, agriculture resources, biological resources, cultural resources, geology and soils, hydrology and water quality, land use and planning, mineral resources, noise, population and housing, public services, recreation, solid/hazardous waste and transportation and traffic are expected as a result of the implementation of PAR 1110.2.

APPENDIX A (OF THE INITIAL STUDY)

PROPOSED RULE 1110.2

In order to save space and avoid repetition, please refer to the latest version of proposed amended Rule 1110.2 located elsewhere in Appendix B of the Draft EA. The April 24 2007 version of the proposed amended rule was circulated with the Notice of Preparation/Initial Study (NOP/IS) that was released on April 26, 2007 for a 30-day public review and comment period ending May 25, 2007.

Hard copies of this NOP/IS, which include the version "PAR 1110.2 (April 24 2007)" of the proposed amended rule, can be obtained through the SCAQMD Public Information Center at the Diamond Bar headquarters or by calling (909) 396-2039

APPENDIX B (OF THE INITIAL STUDY)

ASSUMPTIONS AND CALCULATIONS

Table B-1
PAR 1110.2 Emission Calculations - Summary (tons per day)

Description	Emissions NOx, ton/day	Emissions CO, ton/day	Emissions VOC, ton/ year	Emission Reductions NOx, ton/day	Emission Reductions CO, ton/day	Emission Reductions VOC, ton/day
Calculated Baseline	3.00	10.91	1.25			
Estimated Actual Baseline (Including Excess Emiss.)	4.26	52.98	8.64			
Calculated Emissions beginning 6/1/2007	4.20	52.67	8.62	0.06	0.31	0.03
Calculated Emissions as of 7/1/2008	2.92	10.76	1.24	1.28	41.91	7.37
Calculated Emissions beginning 7/1/2010	2.68	8.60	1.00	0.24	2.17	0.24
Calculated Emissions beginning 7/1/2011	2.46	7.66	0.98	0.21	0.94	0.02
Calculated Emissions beginning 7/1/2012	1.35	3.81	0.86	1.12	3.85	0.12
Totals				2.91	49.17	7.78

Calculated emissions are based on reported fuel use. NOx emissions are based on the NOx limit of each engine or the reported NOx for RECLAIM major sources or if the AER-reported NOx exceeds the calculated NOx based on the NOx limit. CO and VOC emissions are based on the CO and VOC limits for BACT engines. For non-BACT engines, CO and VOC emissions are based on the averaged source test results for the engine or on the average source test results for the category (if there are no source test data for that engine). Emissions are scaled up by a 1/0.696 factor to account for a 69.6% survey response rate.
Excess emissions are based on the results of AQMD unannounced tests, which showed the following results, on average, in terms of the ratio (R) of the measured pollutant concentration to the concentration limit (L):

Rich-burn engines without CEMS:	R-NOx = 2.12 x (45.85 / L-NOx)^0.647
	R-CO = 0.7 x (2000 / L-CO)^0.692
Rich-burn engines with CEMS:	R-NOx = 0.115
	R-CO = 3.65 x (2000 / L-CO)^0.692
Lean-Burn non-biogas BACT engines w/o CEMS:	R-NOx = 1.81
	R-CO = 0.33
In all cases, it is assumed that R-VOC = R-CO	

For the one RECLAIM-major, BACT, rich-burn engine, the excess-emission formula is not applied since the reported NOx emission is close to the BACT NOx limit, suggesting that the engine is not being operated at excessively low NOx as has been observed on average for other rich-burn engines with CEMS.
For RECLAIM-non-major, non-BACT, rich-burn engines, the excess NOx emission formula is not applied if the NOx limit exceeds 100 ppm at 15% O2 since this is considered too far beyond the range of the data upon which the formula is based. In those cases, the excess NOx emission is assumed to be zero.
Emission reductions beginning 6/1/2007 reflect the elimination of elevated emission limits based on efficiency for non-biogas engines and restriction of non-biogas fuel use in biogas engines that are using the elevated emission limits. The biogas/non-biogas portions of these reductions are as follows: NOx- 0.048 /0.024, CO- 0.207/0.160, VOC-0.019/0.018.
Further reductions beginning 7/1/2008 reflect the effects of increased CEMS monitoring, addition of CEMS CO monitoring, and initiation of inspection and monitoring programs for non-CEMS engines--all of which, combined, are expected to eliminate the excess emissions by 7/1/2008.
Further reductions beginning 7/1/2010 are the result of reducing emission limits on non-biogas engines that are 500 bhp and larger to current non-biogas BACT levels (11 ppm NOx, 70 ppm CO and 30 ppm VOC, all at 15% O2).
Further reductions beginning 7/1/2011 are the result of reducing emission limits on non-biogas engines smaller than 500 bhp to current non-biogas BACT levels.
Further reductions beginning 7/1/2012 are the result of reducing emission limits on biogas engines to current non-biogas BACT levels.

Table B-2
PAR1110.2 - Energy Analysis

Facility ID No.	Appl. No.	Engine HP	Engine Use	(d)(1)(B) Reduced Limits, 500+ HP 7/1/10	(d)(1)(B) Reduced Limits <500 HP 7/1/11	(d)(1)(C) Reduced Limits Biogas 7/1/12	Electric Use CEMS, MW-hr/yr	Electric Use Engine, MW-hr/yr	Electric Use Cat Ox, MW-hr/yr	Electric Use Cat Ox, MW-hr/yr	Electric Use SCR, MW-hr/yr	Electric Total, MW-hr/yr	Natural Gas Electric, MMscf/yr	Natural Gas Cat Ox, MMscf/yr	Natural Gas SCR, MMscf/yr
Biogas, BACT, =>1000															
025070	394362	4261	Generator			SCR	0	0	0	0	58.2	58.2	0	0	0
025070	394363	4261	Generator			SCR	0	0	0	0	58.2	58.2	0	0	0
025070	394364	4261	Generator			SCR	0	0	0	0	58.2	58.2	0	0	0
9163	323773	1988	Generator			SCR	0	0	0	0	27.2	27.2	0	0	0
9163	323774	1988	Generator			SCR	0	0	0	0	27.2	27.2	0	0	0
113674	430422	1877	Generator			SCR	0	0	0	0	25.6	25.6	0	0	0
113674	430424	1877	Generator			SCR	0	0	0	0	25.6	25.6	0	0	0
113674	430726	1877	Generator			SCR	0	0	0	0	25.6	25.6	0	0	0
50310	437561	1877	Generator			SCR	0	0	0	0	25.6	25.6	0	0	0
50310	437562	1877	Generator			SCR	0	0	0	0	25.6	25.6	0	0	0
50310	437563	1877	Generator			SCR	0	0	0	0	25.6	25.6	0	0	0
50310	437564	1877	Generator			SCR	0	0	0	0	25.6	25.6	0	0	0
50310	437565	1877	Generator			SCR	0	0	0	0	25.6	25.6	0	0	0
6979	438643	1777	Generator			SCR	0	0	0	0	24.3	24.3	0	0	0
140846	430412	1468	Generator			SCR	0	0	0	0	20.1	20.1	0	0	0
74413	390032	1350	Generator			SCR	0	0	0	0	18.4	18.4	0	0	0
Biogas, BACT, <1000															
013088	414294	400	Compressor			SCR	20	0	0	0	0.0	20.1	0	0	26
Biogas, Non-BACT, =>1000															
104806	323139	4235	Generator			SCR	0	0	0	0	57.9	57.9	0	0	0
104806	323140	4235	Generator			SCR	0	0	0	0	57.9	57.9	0	0	0
29110	414653	4166	Generator			SCR	0	0	0	0	56.9	56.9	0	0	0
29110	414654	4166	Generator			SCR	0	0	0	0	56.9	56.9	0	0	0
29110	414655	4166	Generator			SCR	0	0	0	0	56.9	56.9	0	0	0
29110	414656	4166	Generator			SCR	0	0	0	0	56.9	56.9	0	0	0
29110	414657	4166	Generator			SCR	0	0	0	0	56.9	56.9	0	0	0
17301	414648	3471	Generator			SCR	0	0	0	0	47.4	47.4	0	0	0
17301	414650	3471	Generator			SCR	0	0	0	0	47.4	47.4	0	0	0
17301	414651	3471	Generator			SCR	0	0	0	0	47.4	47.4	0	0	0
113518	414941	2650	Generator			SCR	0	0	0	0	36.2	36.2	0	0	0
113518	414942	2650	Generator			SCR	0	0	0	0	36.2	36.2	0	0	0
113518	414943	2650	Generator			SCR	0	0	0	0	36.2	36.2	0	0	0
142408	437742	2650	Generator			SCR	0	0	0	0	36.2	36.2	0	0	0
142408	437743	2650	Generator			SCR	0	0	0	0	36.2	36.2	0	0	0
142408	437744	2650	Generator			SCR	0	0	0	0	36.2	36.2	0	0	0
142408	437745	2650	Generator			SCR	0	0	0	0	36.2	36.2	0	0	0
142408	437746	2650	Generator			SCR	0	0	0	0	36.2	36.2	0	0	0

Table B-2 (Continued)
PAR1110.2 - Energy Analysis

Facility ID No.	Appl. No.	Engine HP	Engine Use	(d)(1)(B) Reduced Limits, 500+ HP 7/1/10	(d)(1)(B) Reduced Limits <500 HP 7/1/11	(d)(1)(C) Reduced Limits Biogas 7/1/12	Electric Use CEMS, MW-hr/yr	Electric Use Engine, MW-hr/yr	Electric Use Cat Ox, MW-hr/yr	Electric Use Cat Ox, MW-hr/yr	Electric Use SCR, MW-hr/yr	Electric Total, MW-hr/yr	Natural Gas Electric, MMscf/yr	Natural Gas Cat Ox, MMscf/yr	Natural Gas SCR, MMscf/yr
142417	437754	2650	Generator			SCR	0	0	0	0	36.2	36.2	0	0	0
142417	437755	2650	Generator			SCR	0	0	0	0	36.2	36.2	0	0	0
9961	301547	1599	Generator			SCR	0	0	0	0	21.8	21.8	0	0	0
9961	301548	1599	Generator			SCR	0	0	0	0	21.8	21.8	0	0	0
9961	301549	1599	Generator			SCR	0	0	0	0	21.8	21.8	0	0	0
135216	411148	1408	Generator			SCR	0	0	0	0	19.2	19.2	0	0	0
135216	411147	1158	Generator			SCR	0	0	0	0	15.8	15.8	0	0	0
Biogas, Non-BACT <1000															
9163	433835	920	Generator			SCR	20	0	0	0	12.6	32.7	0	0	0
1179	438072	911	Generator			SCR	0	0	0	0	12.4	12.4	0	0	0
11301	160410	750	Generator			SCR	20	0	0	0	10.2	30.4	0	0	0
11301	160411	750	Generator			SCR	0	0	0	0	10.2	10.2	0	0	0
022674	351750	705	Generator			SCR	0	0	0	0	9.6	9.6	0	0	0
13433	319394	580	Generator			SCR	20	0	0	0	7.9	28.1	0	0	0
13433	319395	580	Generator			SCR	0	0	0	0	7.9	7.9	0	0	0
13433	319396	580	Generator			SCR	0	0	0	0	7.9	7.9	0	0	0
3866	172772	636	Compressor			SCR	0	0	0	0	0	0	0	0	41
001703	373739	530	Compressor			SCR	20	0	0	0	0	20.1	0	0	34
001703	373740	530	Compressor			SCR	0	0	0	0	0	0	0	0	34
019159	416944	260	Compressor			SCR	20	0	0	0	0	20.1	0	0	17
Non-Biogas, RECLAIM, BACT, Rich, Major															
68118	436966	2000	Pump				0	0	0	0	0	0	0	0	0
Non-Biogas, RECLAIM, BACT, Rich, Non-Major															
800128	367656	818	Generator				20	0	0	0	0	20.1	0	0	0
800128	367657	818	Generator				0	0	0	0	0	0	0	0	0
800128	367658	818	Generator				0	0	0	0	0	0	0	0	0
800128	367659	818	Generator				0	0	0	0	0	0	0	0	0
18455	406950	600	Generator				20	0	0	0	0	20.1	0	0	0
18455	406951	564	Generator				0	0	0	0	0	0	0	0	0
18455	406952	564	Generator				0	0	0	0	0	0	0	0	0
141012	432686	790	Compressor				20	0	0	0	0	20.1	0	0	0
141012	432687	790	Compressor				0	0	0	0	0	0	0	0	0
800127	274839	750	Compressor				20	0	0	0	0	20.1	0	0	0
346	335791	545	Compressor				0	0	0	0	0	0	0	0	0
100844	425811	412	Compressor				0	0	0	0	0	0	0	0	0
6714	408065	283	Pump				0	0	0	0	0	0	0	0	0
6714	408067	283	Pump				0	0	0	0	0	0	0	0	0
6714	408064	116	Pump				0	0	0	0	0	0	0	0	0

Table B-2 (Continued)
PAR1110.2 - Energy Analysis

Facility ID No.	Appl. No.	Engine HP	Engine Use	(d)(1)(B) Reduced Limits, 500+ HP 7/1/10	(d)(1)(B) Reduced Limits <500 HP 7/1/11	(d)(1)(C) Reduced Limits Biogas 7/1/12	Electric Use CEMS, MW-hr/yr	Electric Use Engine, MW-hr/yr	Electric Use Cat Ox, MW-hr/yr	Electric Use Cat Ox, MW-hr/yr	Electric Use SCR, MW-hr/yr	Electric Total, MW-hr/yr	Natural Gas Electric, MMscf/yr	Natural Gas Cat Ox, MMscf/yr	Natural Gas SCR, MMscf/yr
6714	408068	116	Pump				0	0	0	0	0	0	0	0	0
Non-Biogas, RECLAIM, Non-BACT, Rich, Major															
130211	414383	2068	Generator	Upgrade			0	0	0	0	0	0	0	0	0
Non-Biogas, RECLAIM, Non-BACT, Rich, Non-Major															
98159	332851	870	Generator	Upgrade			0	0	0	0	0	0	0	0	0
5973	362357	818	Generator	Upgrade			20	0	0	0	0	20.1	0	0	0
5973	362358	818	Generator	Upgrade			0	0	0	0	0	0	0	0	0
5973	362359	818	Generator	Upgrade			0	0	0	0	0	0	0	0	0
54547	171158	125	Generator		Upgrade		0	0	0	0	0	0	0	0	0
5973	101703	738	Compressor	Upgrade			0	0	0	0	0	0	0	0	0
5973	101704	738	Compressor	Upgrade			0	0	0	0	0	0	0	0	0
75531	319404	250	Compressor		Upgrade		0	0	0	0	0	0	0	0	0
75531	319405	250	Compressor		Upgrade		0	0	0	0	0	0	0	0	0
11034	190074	132	Compressor		Upgrade		20	0	0	0	0	20.1	0	0	0
11034	190075	132	Compressor		Upgrade		0	0	0	0	0	0	0	0	0
11034	190076	132	Compressor		Upgrade		0	0	0	0	0	0	0	0	0
800189	457331	708	Pump	Upgrade			20	0	0	0	0	20.1	0	0	0
800189	457332	708	Pump	Upgrade			0	0	0	0	0	0	0	0	0
11034	156967	377	Pump		Upgrade		20	0	0	0	0	20.1	0	0	0
11034	156968	377	Pump		Upgrade		0	0	0	0	0	0	0	0	0
9053	434478	377	Pump		Upgrade		20	0	0	0	0	20.1	0	0	0
9053	434498	377	Pump		Upgrade		0	0	0	0	0	0	0	0	0
9053	434501	377	Pump		Upgrade		0	0	0	0	0	0	0	0	0
11034	156966	287	Pump		Upgrade		20	0	0	0	0	20.1	0	0	0
9053	434502	244	Pump		Upgrade		20	0	0	0	0	20.1	0	0	0
9053	434503	244	Pump		Upgrade		0	0	0	0	0	0	0	0	0
9053	434504	244	Pump		Upgrade		0	0	0	0	0	0	0	0	0
800189	457324	218	Pump		Upgrade		20	0	0	0	0	20.1	0	0	0
800189	457335	218	Pump		Upgrade		0	0	0	0	0	0	0	0	0
11034	190071	193	Pump		Upgrade		20	0	0	0	0	20.1	0	0	0
11034	190072	193	Pump		Upgrade		0	0	0	0	0	0	0	0	0
11034	190073	193	Pump		Upgrade		0	0	0	0	0	0	0	0	0
800189	457334	151	Pump		Upgrade		20	0	0	0	0	20.1	0	0	0
800189	457325	102	Pump		Upgrade		0	0	0	0	0	0	0	0	0
800189	457326	102	Pump		Upgrade		0	0	0	0	0	0	0	0	0
8582	198426	97	Pump		Upgrade		20	0	0	0	0	20.1	0	0	0
8582	198427	97	Pump		Upgrade		0	0	0	0	0	0	0	0	0
8582	198428	97	Pump		Upgrade		0	0	0	0	0	0	0	0	0

Table B-2 (Continued)
PAR1110.2 - Energy Analysis

Facility ID No.	Appl. No.	Engine HP	Engine Use	(d)(1)(B) Reduced Limits, 500+ HP 7/1/10	(d)(1)(B) Reduced Limits <500 HP 7/1/11	(d)(1)(C) Reduced Limits Biogas 7/1/12	Electric Use CEMS, MW-hr/yr	Electric Use Engine, MW-hr/yr	Electric Use Cat Ox, MW-hr/yr	Electric Use Cat Ox, MW-hr/yr	Electric Use SCR, MW-hr/yr	Electric Total, MW-hr/yr	Natural Gas Electric, MMscf/yr	Natural Gas Cat Ox, MMscf/yr	Natural Gas SCR, MMscf/yr
9217	196405	86	Pump		Upgrade		0	0	0	0	0	0	0	0	0
9217	196409	86	Pump		Upgrade		0	0	0	0	0	0	0	0	0
Non-Biogas, RECLAIM, Non-BACT, Lean, Major, 4-Stroke															
5973	147546	5500	Compressor	Ox Cat			0	0	0	0	0	0	0	0	0
5973	156060	5500	Compressor	Ox Cat			0	0	0	0	0	0	0	0	0
5973	156061	5500	Compressor	Ox Cat			0	0	0	0	0	0	0	0	0
5973	156062	5500	Compressor	Ox Cat			0	0	0	0	0	0	0	0	0
5973	156063	5500	Compressor	Ox Cat			0	0	0	0	0	0	0	0	0
800128	153507	2000	Compressor	Ox Cat			0	0	0	0	0	0	0	0	0
800128	159101	2000	Compressor	Ox Cat			0	0	0	0	0	0	0	0	0
800128	159102	2000	Compressor	Ox Cat			0	0	0	0	0	0	0	0	0
800128	159103	2000	Compressor	Ox Cat			0	0	0	0	0	0	0	0	0
800128	159104	2000	Compressor	Ox Cat			0	0	0	0	0	0	0	0	0
9053	434505	1650	Compressor	Ox Cat			0	0	0	0	0	0	0	0	0
9053	434506	1650	Compressor	Ox Cat			0	0	0	0	0	0	0	0	0
9053	434507	1650	Compressor	Ox Cat			0	0	0	0	0	0	0	0	0
Non-Biogas, RECLAIM, Non-BACT, Lean, Major, 2-Stroke															
4242	170675	3000	Generator	Electric			0	17,367	0	0	0	17,367	-193	0	0
8582	368116	2000	Compressor	Electric			0	12,305	0	0	0	12,305	-129	0	0
8582	368117	2000	Compressor	Electric			0	12,305	0	0	0	12,305	-129	0	0
8582	368118	2000	Compressor	Electric			0	12,305	0	0	0	12,305	-129	0	0
4242	169829	3200	Compressor	Electric			0	19,688	0	0	0	19,688	-206	0	0
4242	172126	3000	Compressor	Electric			0	18,458	0	0	0	18,458	-193	0	0
800127	327697	1800	Compressor	Electric			0	11,075	0	0	0	11,075	-116	0	0
800127	327699	1800	Compressor	Electric			0	11,075	0	0	0	11,075	-116	0	0
8582	311760	1350	Compressor	Electric			0	8,306	0	0	0	8,306	-87	0	0
8582	311761	1350	Compressor	Electric			0	8,306	0	0	0	8,306	-87	0	0
8582	311755	1100	Compressor	Electric			0	6,768	0	0	0	6,768	-71	0	0
8582	311756	1100	Compressor	Electric			0	6,768	0	0	0	6,768	-71	0	0
4242	364371	995	Compressor	Electric			20	6,122	0	0	0	6,142	-64	0	0
4242	364373	995	Compressor	Electric			0	6,122	0	0	0	6,122	-64	0	0
4242	364374	995	Compressor	Electric			0	6,122	0	0	0	6,122	-64	0	0
Non-Biogas, RECLAIM, Non-BACT, Lean, Non-Major															
17953	384810	810	Generator	Ox Cat			0	0	3.47	0	0	3.5	0	0	0
800127	169969	328	Generator		Ox Cat		20	0	0	1.41	0	21.6	0	0	0
800127	169970	328	Generator		Ox Cat		0	0	0	1.41	0	1.4	0	0	0
800127	169971	328	Generator		Ox Cat		0	0	0	1.41	0	1.4	0	0	0
800127	169972	328	Generator		Ox Cat		0	0	0	1.41	0	1.4	0	0	0

Table B-2 (Continued)
PAR1110.2 - Energy Analysis

Facility ID No.	Appl. No.	Engine HP	Engine Use	(d)(1)(B) Reduced Limits, 500+ HP 7/1/10	(d)(1)(B) Reduced Limits <500 HP 7/1/11	(d)(1)(C) Reduced Limits Biogas 7/1/12	Electric Use CEMS, MW-hr/yr	Electric Use Engine, MW-hr/yr	Electric Use Cat Ox, MW-hr/yr	Electric Use Cat Ox, MW-hr/yr	Electric Use SCR, MW-hr/yr	Electric Total, MW-hr/yr	Natural Gas Electric, MMscf/yr	Natural Gas Cat Ox, MMscf/yr	Natural Gas SCR, MMscf/yr
101369	292228	88	Generator		Ox Cat		0	0	0	0.38	0	0.4	0	0	0
800363	347919	300	Compressor		Ox Cat		0	0	0	0	0	0	0	0	0
800189	457333	218	Pump		Ox Cat		20	0	0	0	0	20.1	0	0	0
Non-Biogas, Non-RECLAIM, BACT, Rich, =>1000															
007417	409351	2200	Generator				0	0	0	0	0	0	0	0	0
11245	406575	2080	Generator				0	0	0	0	0	0	0	0	0
11245	406576	2080	Generator				0	0	0	0	0	0	0	0	0
11245	406577	2080	Generator				0	0	0	0	0	0	0	0	0
132687	401752	1898	Generator				0	0	0	0	0	0	0	0	0
132687	401753	1898	Generator				0	0	0	0	0	0	0	0	0
129033	388869	1695	Generator				0	0	0	0	0	0	0	0	0
129033	388870	1695	Generator				0	0	0	0	0	0	0	0	0
129033	388871	1695	Generator				0	0	0	0	0	0	0	0	0
129033	388873	1695	Generator				0	0	0	0	0	0	0	0	0
129033	388875	1695	Generator				0	0	0	0	0	0	0	0	0
129033	388876	1695	Generator				0	0	0	0	0	0	0	0	0
129033	388877	1695	Generator				0	0	0	0	0	0	0	0	0
3513	399704	1692	Generator				0	0	0	0	0	0	0	0	0
3513	399705	1692	Generator				0	0	0	0	0	0	0	0	0
6324	416768	1478	Generator				0	0	0	0	0	0	0	0	0
6324	416769	1478	Generator				0	0	0	0	0	0	0	0	0
67399	401572	1470	Generator				0	0	0	0	0	0	0	0	0
43880	434981	1050	Compressor				0	0	0	0	0	0	0	0	0
43880	434982	1050	Compressor				0	0	0	0	0	0	0	0	0
43880	434983	1050	Compressor				0	0	0	0	0	0	0	0	0
136965	416861	2000	Pump				0	0	0	0	0	0	0	0	0
68112	423950	2000	Pump				0	0	0	0	0	0	0	0	0
800236	377389	1564	Pump				0	0	0	0	0	0	0	0	0
800236	377395	1564	Pump				0	0	0	0	0	0	0	0	0
800236	377397	1564	Pump				0	0	0	0	0	0	0	0	0
800236	377399	1564	Pump				0	0	0	0	0	0	0	0	0
800236	377400	1564	Pump				0	0	0	0	0	0	0	0	0
Non-Biogas, Non-RECLAIM, BACT, Rich, <1000															
96326	434798	999	Generator				20	0	0	0	0	20.1	0	0	0
96326	434799	999	Generator				0	0	0	0	0	0	0	0	0
1912	408888	998	Generator				20	0	0	0	0	20.1	0	0	0
1912	408889	998	Generator				0	0	0	0	0	0	0	0	0
001703	299074	930	Generator				20	0	0	0	0	20.1	0	0	0

Table B-2 (Continued)
PAR1110.2 - Energy Analysis

Facility ID No.	Appl. No.	Engine HP	Engine Use	(d)(1)(B) Reduced Limits, 500+ HP 7/1/10	(d)(1)(B) Reduced Limits <500 HP 7/1/11	(d)(1)(C) Reduced Limits Biogas 7/1/12	Electric Use CEMS, MW-hr/yr	Electric Use Engine, MW-hr/yr	Electric Use Cat Ox, MW-hr/yr	Electric Use Cat Ox, MW-hr/yr	Electric Use SCR, MW-hr/yr	Electric Total, MW-hr/yr	Natural Gas Electric, MMscf/yr	Natural Gas Cat Ox, MMscf/yr	Natural Gas SCR, MMscf/yr
001703	331502	930	Generator				0	0	0	0	0	0	0	0	0
120088	387989	930	Generator				20	0	0	0	0	20.1	0	0	0
120088	387990	930	Generator				0	0	0	0	0	0	0	0	0
121454	387995	930	Generator				20	0	0	0	0	20.1	0	0	0
121454	387996	930	Generator				0	0	0	0	0	0	0	0	0
131709	398473	930	Generator				0	0	0	0	0	0	0	0	0
45063	396528	840	Generator				0	0	0	0	0	0	0	0	0
19185	428146	800	Generator				20	0	0	0	0	20.1	0	0	0
138723	422556	792	Generator				20	0	0	0	0	20.1	0	0	0
138723	422557	792	Generator				0	0	0	0	0	0	0	0	0
58639	390872	791	Generator				20	0	0	0	0	20.1	0	0	0
79174	385862	738	Generator				0	0	0	0	0	0	0	0	0
131258	420975	643	Generator				0	0	0	0	0	0	0	0	0
99201	421763	585	Generator				20	0	0	0	0	20.1	0	0	0
139280	424326	585	Generator				0	0	0	0	0	0	0	0	0
99201	421980	584	Generator				20	0	0	0	0	20.1	0	0	0
19185	428143	543	Generator				20	0	0	0	0	20.1	0	0	0
89159	422466	531	Generator				0	0	0	0	0	0	0	0	0
133176	403608	530	Generator				20	0	0	0	0	20.1	0	0	0
133176	403610	530	Generator				0	0	0	0	0	0	0	0	0
133176	403611	530	Generator				0	0	0	0	0	0	0	0	0
132251	409035	530	Generator				20	0	0	0	0	20.1	0	0	0
132251	409036	530	Generator				0	0	0	0	0	0	0	0	0
138293	421366	530	Generator				20	0	0	0	0	20.1	0	0	0
138293	421367	530	Generator				0	0	0	0	0	0	0	0	0
138293	421368	530	Generator				0	0	0	0	0	0	0	0	0
138851	422959	530	Generator				20	0	0	0	0	20.1	0	0	0
138851	422960	530	Generator				0	0	0	0	0	0	0	0	0
141084	431261	530	Generator				20	0	0	0	0	20	0	0	0
141084	431262	530	Generator				0	0	0	0	0	0	0	0	0
70769	408911	495	Generator				0	0	0	0	0	0	0	0	0
140945	430753	380	Generator				0	0	0	0	0	0	0	0	0
65819	389615	366	Generator				0	0	0	0	0	0	0	0	0
137369	418087	350	Generator				0	0	0	0	0	0	0	0	0
118124	417507	336	Generator				0	0	0	0	0	0	0	0	0
118124	417508	336	Generator				0	0	0	0	0	0	0	0	0
131157	391590	310	Generator				20	0	0	0	0	20.1	0	0	0
131157	391591	310	Generator				0	0	0	0	0	0	0	0	0

Table B-2 (Continued)
PAR1110.2 - Energy Analysis

Facility ID No.	Appl. No.	Engine HP	Engine Use	(d)(1)(B) Reduced Limits, 500+ HP 7/1/10	(d)(1)(B) Reduced Limits <500 HP 7/1/11	(d)(1)(C) Reduced Limits Biogas 7/1/12	Electric Use CEMS, MW-hr/yr	Electric Use Engine, MW-hr/yr	Electric Use Cat Ox, MW-hr/yr	Electric Use Cat Ox, MW-hr/yr	Electric Use SCR, MW-hr/yr	Electric Total, MW-hr/yr	Natural Gas Electric, MMscf/yr	Natural Gas Cat Ox, MMscf/yr	Natural Gas SCR, MMscf/yr
131157	391592	310	Generator				0	0	0	0	0	0	0	0	0
131157	391593	310	Generator				0	0	0	0	0	0	0	0	0
131157	391594	310	Generator				0	0	0	0	0	0	0	0	0
131157	391596	310	Generator				0	0	0	0	0	0	0	0	0
131157	391597	310	Generator				0	0	0	0	0	0	0	0	0
131157	391598	310	Generator				0	0	0	0	0	0	0	0	0
131157	391599	310	Generator				0	0	0	0	0	0	0	0	0
123684	395143	310	Generator				0	0	0	0	0	0	0	0	0
131156	396199	310	Generator				0	0	0	0	0	0	0	0	0
131155	396200	310	Generator				0	0	0	0	0	0	0	0	0
138279	421318	310	Generator				0	0	0	0	0	0	0	0	0
141363	432379	310	Generator				0	0	0	0	0	0	0	0	0
143086	438530	310	Generator				20	0	0	0	0	20.1	0	0	0
143086	438531	310	Generator				0	0	0	0	0	0	0	0	0
143086	438533	310	Generator				0	0	0	0	0	0	0	0	0
143086	438534	310	Generator				0	0	0	0	0	0	0	0	0
133802	405959	282	Generator				20	0	0	0	0	20.1	0	0	0
133802	405960	282	Generator				0	0	0	0	0	0	0	0	0
133802	405961	282	Generator				0	0	0	0	0	0	0	0	0
133802	405962	282	Generator				0	0	0	0	0	0	0	0	0
141084	431264	282	Generator				20	0	0	0	0	20.1	0	0	0
129336	389961	275	Generator				0	0	0	0	0	0	0	0	0
140947	430760	270	Generator				0	0	0	0	0	0	0	0	0
140947	430762	270	Generator				0	0	0	0	0	0	0	0	0
140947	430764	270	Generator				0	0	0	0	0	0	0	0	0
141199	435531	270	Generator				0	0	0	0	0	0	0	0	0
141199	435532	270	Generator				0	0	0	0	0	0	0	0	0
141199	435533	270	Generator				0	0	0	0	0	0	0	0	0
135490	412041	268	Generator				0	0	0	0	0	0	0	0	0
135490	412042	268	Generator				0	0	0	0	0	0	0	0	0
135490	412043	268	Generator				0	0	0	0	0	0	0	0	0
45938	417562	240	Generator				0	0	0	0	0	0	0	0	0
2638	320968	225	Generator				0	0	0	0	0	0	0	0	0
2638	320969	225	Generator				0	0	0	0	0	0	0	0	0
131426	431200	220	Generator				0	0	0	0	0	0	0	0	0
131426	431201	220	Generator				0	0	0	0	0	0	0	0	0
130085	392437	210	Generator				0	0	0	0	0	0	0	0	0
134448	408357	210	Generator				0	0	0	0	0	0	0	0	0

Table B-2 (Continued)
PAR1110.2 - Energy Analysis

Facility ID No.	Appl. No.	Engine HP	Engine Use	(d)(1)(B) Reduced Limits, 500+ HP 7/1/10	(d)(1)(B) Reduced Limits <500 HP 7/1/11	(d)(1)(C) Reduced Limits Biogas 7/1/12	Electric Use CEMS, MW-hr/yr	Electric Use Engine, MW-hr/yr	Electric Use Cat Ox, MW-hr/yr	Electric Use Cat Ox, MW-hr/yr	Electric Use SCR, MW-hr/yr	Electric Total, MW-hr/yr	Natural Gas Electric, MMscf/yr	Natural Gas Cat Ox, MMscf/yr	Natural Gas SCR, MMscf/yr
134449	408359	210	Generator				0	0	0	0	0	0	0	0	0
138055	420563	210	Generator				0	0	0	0	0	0	0	0	0
138056	420564	210	Generator				0	0	0	0	0	0	0	0	0
140466	428824	210	Generator				0	0	0	0	0	0	0	0	0
82513	433441	202	Generator				20	0	0	0	0	20.1	0	0	0
82513	433442	202	Generator				0	0	0	0	0	0	0	0	0
82513	433443	202	Generator				0	0	0	0	0	0	0	0	0
82513	433444	202	Generator				0	0	0	0	0	0	0	0	0
82513	433445	202	Generator				0	0	0	0	0	0	0	0	0
82513	433446	202	Generator				0	0	0	0	0	0	0	0	0
132653	435512	195	Generator				0	0	0	0	0	0	0	0	0
137976	435522	195	Generator				0	0	0	0	0	0	0	0	0
137976	435523	195	Generator				0	0	0	0	0	0	0	0	0
138791	422748	173	Generator				0	0	0	0	0	0	0	0	0
132182	400404	162	Generator				0	0	0	0	0	0	0	0	0
129434	390240	157	Generator				0	0	0	0	0	0	0	0	0
5023	387253	149	Generator				0	0	0	0	0	0	0	0	0
5023	387254	149	Generator				0	0	0	0	0	0	0	0	0
45882	387483	135	Generator				0	0	0	0	0	0	0	0	0
83509	416748	135	Generator				0	0	0	0	0	0	0	0	0
83509	416749	135	Generator				0	0	0	0	0	0	0	0	0
133802	405963	110	Generator				20	0	0	0	0	20.1	0	0	0
70989	281036	101	Generator				0	0	0	0	0	0	0	0	0
34961	321188	94	Generator				0	0	0	0	0	0	0	0	0
34961	321189	94	Generator				0	0	0	0	0	0	0	0	0
120956	361525	93.8	Generator				0	0	0	0	0	0	0	0	0
116813	372297	86	Generator				0	0	0	0	0	0	0	0	0
116813	372298	86	Generator				0	0	0	0	0	0	0	0	0
116813	372299	86	Generator				0	0	0	0	0	0	0	0	0
16211	403396	86	Generator				0	0	0	0	0	0	0	0	0
16211	403879	86	Generator				0	0	0	0	0	0	0	0	0
16211	403881	86	Generator				0	0	0	0	0	0	0	0	0
16211	403882	86	Generator				0	0	0	0	0	0	0	0	0
16211	403884	86	Generator				0	0	0	0	0	0	0	0	0
16211	403886	86	Generator				0	0	0	0	0	0	0	0	0
129025	388842	80	Generator				0	0	0	0	0	0	0	0	0
129664	391023	80	Generator				0	0	0	0	0	0	0	0	0
115471	409783	74	Generator				0	0	0	0	0	0	0	0	0

Table B-2 (Continued)
PAR1110.2 - Energy Analysis

Facility ID No.	Appl. No.	Engine HP	Engine Use	(d)(1)(B) Reduced Limits, 500+ HP 7/1/10	(d)(1)(B) Reduced Limits <500 HP 7/1/11	(d)(1)(C) Reduced Limits Biogas 7/1/12	Electric Use CEMS, MW-hr/yr	Electric Use Engine, MW-hr/yr	Electric Use Cat Ox, MW-hr/yr	Electric Use Cat Ox, MW-hr/yr	Electric Use SCR, MW-hr/yr	Electric Total, MW-hr/yr	Natural Gas Electric, MMscf/yr	Natural Gas Cat Ox, MMscf/yr	Natural Gas SCR, MMscf/yr
115471	409784	74	Generator				0	0	0	0	0	0	0	0	0
115471	409785	74	Generator				0	0	0	0	0	0	0	0	0
43759	434971	800	Compressor				20	0	0	0	0	20.1	0	0	0
43759	434972	800	Compressor				0	0	0	0	0	0	0	0	0
43759	434973	800	Compressor				0	0	0	0	0	0	0	0	0
22265	434975	800	Compressor				20	0	0	0	0	20.1	0	0	0
22265	434976	800	Compressor				0	0	0	0	0	0	0	0	0
22265	434977	800	Compressor				0	0	0	0	0	0	0	0	0
013088	342013	700	Compressor				20	0	0	0	0	20.1	0	0	0
013088	416840	700	Compressor				0	0	0	0	0	0	0	0	0
134325	407959	607	Compressor				20	0	0	0	0	20.1	0	0	0
134325	407960	607	Compressor				0	0	0	0	0	0	0	0	0
134325	407961	607	Compressor				0	0	0	0	0	0	0	0	0
134326	407963	607	Compressor				0	0	0	0	0	0	0	0	0
134326	407964	607	Compressor				0	0	0	0	0	0	0	0	0
134326	407965	607	Compressor				0	0	0	0	0	0	0	0	0
134329	407967	607	Compressor				20	0	0	0	0	20.1	0	0	0
134329	407968	607	Compressor				0	0	0	0	0	0	0	0	0
134329	407969	607	Compressor				0	0	0	0	0	0	0	0	0
83111	385480	585	Compressor				0	0	0	0	0	0	0	0	0
18517	434978	530	Compressor				20	0	0	0	0	20.1	0	0	0
18517	434979	530	Compressor				0	0	0	0	0	0	0	0	0
18517	434980	530	Compressor				0	0	0	0	0	0	0	0	0
001703	331499	465	Compressor				20	0	0	0	0	20.1	0	0	0
8309	342750	450	Compressor				0	0	0	0	0	0	0	0	0
53745	350036	415	Compressor				0	0	0	0	0	0	0	0	0
50645	350037	415	Compressor				0	0	0	0	0	0	0	0	0
111116	388705	405	Compressor				0	0	0	0	0	0	0	0	0
140028	429785	400	Compressor				0	0	0	0	0	0	0	0	0
66086	419537	365	Compressor				0	0	0	0	0	0	0	0	0
66086	419538	365	Compressor				0	0	0	0	0	0	0	0	0
019159	331495	330	Compressor				20	0	0	0	0	20.1	0	0	0
22092	367195	292	Compressor				0	0	0	0	0	0	0	0	0
800041	326508	220	Compressor				0	0	0	0	0	0	0	0	0
123664	370691	203	Compressor				0	0	0	0	0	0	0	0	0
94117	347693	200	Compressor				0	0	0	0	0	0	0	0	0
134328	407966	195	Compressor				0	0	0	0	0	0	0	0	0
134330	407970	195	Compressor				0	0	0	0	0	0	0	0	0

Table B-2 (Continued)
PAR1110.2 - Energy Analysis

Facility ID No.	Appl. No.	Engine HP	Engine Use	(d)(1)(B) Reduced Limits, 500+ HP 7/1/10	(d)(1)(B) Reduced Limits <500 HP 7/1/11	(d)(1)(C) Reduced Limits Biogas 7/1/12	Electric Use CEMS, MW-hr/yr	Electric Use Engine, MW-hr/yr	Electric Use Cat Ox, MW-hr/yr	Electric Use Cat Ox, MW-hr/yr	Electric Use SCR, MW-hr/yr	Electric Total, MW-hr/yr	Natural Gas Electric, MMscf/yr	Natural Gas Cat Ox, MMscf/yr	Natural Gas SCR, MMscf/yr
89852	401453	194	Compressor				0	0	0	0	0	0	0	0	0
64375	386532	158	Compressor				0	0	0	0	0	0	0	0	0
139380	424742	158	Compressor				0	0	0	0	0	0	0	0	0
139380	424743	158	Compressor				0	0	0	0	0	0	0	0	0
139380	424744	158	Compressor				0	0	0	0	0	0	0	0	0
49572	434072	153	Compressor				0	0	0	0	0	0	0	0	0
49572	434472	153	Compressor				0	0	0	0	0	0	0	0	0
49572	434473	153	Compressor				0	0	0	0	0	0	0	0	0
49572	434474	153	Compressor				0	0	0	0	0	0	0	0	0
109393	317735	149	Compressor				0	0	0	0	0	0	0	0	0
109393	317738	149	Compressor				0	0	0	0	0	0	0	0	0
109393	317742	149	Compressor				0	0	0	0	0	0	0	0	0
111345	324916	145	Compressor				0	0	0	0	0	0	0	0	0
18650	328168	145	Compressor				0	0	0	0	0	0	0	0	0
16211	403397	119	Compressor				0	0	0	0	0	0	0	0	0
123664	406670	539	Other				0	0	0	0	0	0	0	0	0
001703	426335	815	Pump				20	0	0	0	0	20.1	0	0	0
001703	373968	814	Pump				0	0	0	0	0	0	0	0	0
96562	353382	750	Pump				20	0	0	0	0	20.1	0	0	0
001703	356818	700	Pump				20	0	0	0	0	20.1	0	0	0
133829	406061	526	Pump				0	0	0	0	0	0	0	0	0
139509	425325	524	Pump				20	0	0	0	0	20.1	0	0	0
139509	425326	524	Pump				0	0	0	0	0	0	0	0	0
139509	425327	524	Pump				0	0	0	0	0	0	0	0	0
111406	416671	512	Pump				0	0	0	0	0	0	0	0	0
54773	415033	473	Pump				20	0	0	0	0	20.1	0	0	0
54773	415034	473	Pump				0	0	0	0	0	0	0	0	0
125016	374784	429	Pump				0	0	0	0	0	0	0	0	0
16239	420868	405	Pump				20	0	0	0	0	20.1	0	0	0
96562	364871	395	Pump				20	0	0	0	0	20.1	0	0	0
96562	364887	395	Pump				0	0	0	0	0	0	0	0	0
98380	292781	369	Pump				20	0	0	0	0	20.1	0	0	0
98380	292782	369	Pump				0	0	0	0	0	0	0	0	0
98380	292784	369	Pump				0	0	0	0	0	0	0	0	0
98380	292785	369	Pump				0	0	0	0	0	0	0	0	0
57555	420687	369	Pump				0	0	0	0	0	0	0	0	0
108286	313977	365	Pump				0	0	0	0	0	0	0	0	0
108293	336542	365	Pump				0	0	0	0	0	0	0	0	0

Table B-2 (Continued)
PAR1110.2 - Energy Analysis

Facility ID No.	Appl. No.	Engine HP	Engine Use	(d)(1)(B) Reduced Limits, 500+ HP 7/1/10	(d)(1)(B) Reduced Limits <500 HP 7/1/11	(d)(1)(C) Reduced Limits Biogas 7/1/12	Electric Use CEMS, MW-hr/yr	Electric Use Engine, MW-hr/yr	Electric Use Cat Ox, MW-hr/yr	Electric Use Cat Ox, MW-hr/yr	Electric Use SCR, MW-hr/yr	Electric Total, MW-hr/yr	Natural Gas Electric, MMscf/yr	Natural Gas Cat Ox, MMscf/yr	Natural Gas SCR, MMscf/yr
108288	339584	365	Pump				0	0	0	0	0	0	0	0	0
070303	405402	365	Pump				0	0	0	0	0	0	0	0	0
54771	415036	350	Pump				0	0	0	0	0	0	0	0	0
16239	321174	329	Pump				20	0	0	0	0	20.1	0	0	0
16239	321175	329	Pump				0	0	0	0	0	0	0	0	0
16239	321176	329	Pump				0	0	0	0	0	0	0	0	0
16239	321177	329	Pump				0	0	0	0	0	0	0	0	0
52718	342367	321	Pump				0	0	0	0	0	0	0	0	0
52718	342369	321	Pump				0	0	0	0	0	0	0	0	0
87640	342373	321	Pump				0	0	0	0	0	0	0	0	0
94996	359880	310	Pump				0	0	0	0	0	0	0	0	0
94998	407123	310	Pump				0	0	0	0	0	0	0	0	0
95000	439777	310	Pump				0	0	0	0	0	0	0	0	0
94677	428124	305	Pump				0	0	0	0	0	0	0	0	0
5322	422131	289	Pump				0	0	0	0	0	0	0	0	0
52886	388444	246	Pump				0	0	0	0	0	0	0	0	0
52886	388445	246	Pump				0	0	0	0	0	0	0	0	0
52886	388447	246	Pump				0	0	0	0	0	0	0	0	0
52886	388449	246	Pump				0	0	0	0	0	0	0	0	0
52883	388459	246	Pump				0	0	0	0	0	0	0	0	0
52883	388462	246	Pump				0	0	0	0	0	0	0	0	0
070309	333800	225	Pump				0	0	0	0	0	0	0	0	0
070292	334717	225	Pump				20	0	0	0	0	20.1	0	0	0
68181	363123	225	Pump				0	0	0	0	0	0	0	0	0
070290	363870	225	Pump				0	0	0	0	0	0	0	0	0
119118	352647	220	Pump				0	0	0	0	0	0	0	0	0
119118	352648	220	Pump				0	0	0	0	0	0	0	0	0
119118	352649	220	Pump				0	0	0	0	0	0	0	0	0
113029	329845	211	Pump				0	0	0	0	0	0	0	0	0
070280	327127	200	Pump				0	0	0	0	0	0	0	0	0
94678	413795	200	Pump				0	0	0	0	0	0	0	0	0
95000	286934	180	Pump				0	0	0	0	0	0	0	0	0
93720	420807	160	Pump				0	0	0	0	0	0	0	0	0
54773	415030	158	Pump				20	0	0	0	0	20.1	0	0	0
54773	415031	158	Pump				0	0	0	0	0	0	0	0	0
54773	415032	158	Pump				0	0	0	0	0	0	0	0	0
66411	279623	157	Pump				0	0	0	0	0	0	0	0	0
2868	279621	145	Pump				0	0	0	0	0	0	0	0	0

Table B-2 (Continued)
PAR1110.2 - Energy Analysis

Facility ID No.	Appl. No.	Engine HP	Engine Use	(d)(1)(B) Reduced Limits, 500+ HP 7/1/10	(d)(1)(B) Reduced Limits <500 HP 7/1/11	(d)(1)(C) Reduced Limits Biogas 7/1/12	Electric Use CEMS, MW-hr/yr	Electric Use Engine, MW-hr/yr	Electric Use Cat Ox, MW-hr/yr	Electric Use Cat Ox, MW-hr/yr	Electric Use SCR, MW-hr/yr	Electric Total, MW-hr/yr	Natural Gas Electric, MMscf/yr	Natural Gas Cat Ox, MMscf/yr	Natural Gas SCR, MMscf/yr
120455	359159	145	Pump				0	0	0	0	0	0	0	0	0
120455	359167	145	Pump				0	0	0	0	0	0	0	0	0
070289	390099	145	Pump				0	0	0	0	0	0	0	0	0
94676	413796	145	Pump				0	0	0	0	0	0	0	0	0
94676	413797	145	Pump				0	0	0	0	0	0	0	0	0
94999	286933	137	Pump				0	0	0	0	0	0	0	0	0
132772	401914	125	Pump				0	0	0	0	0	0	0	0	0
136018	413764	95	Pump				0	0	0	0	0	0	0	0	0
125300	375524	80	Pump				0	0	0	0	0	0	0	0	0
125300	375526	80	Pump				0	0	0	0	0	0	0	0	0
125300	375527	80	Pump				0	0	0	0	0	0	0	0	0
125300	375529	80	Pump				0	0	0	0	0	0	0	0	0
14898	389366	75	Pump				0	0	0	0	0	0	0	0	0
14898	389368	75	Pump				0	0	0	0	0	0	0	0	0
136021	413763	74	Pump				0	0	0	0	0	0	0	0	0
Non-Biogas, Non-RECLAIM, BACT, Lean, =>1000															
3671	408492	3352	Generator				0	0	0	0	0	0	0	0	0
3671	408493	3352	Generator				0	0	0	0	0	0	0	0	0
4773	386614	2682	Generator				0	0	0	0	0	0	0	0	0
4773	386615	2682	Generator				0	0	0	0	0	0	0	0	0
21123	405486	2494	Generator				0	0	0	0	0	0	0	0	0
45973	423225	2307	Generator				0	0	0	0	0	0	0	0	0
102153	403632	2095	Generator				0	0	0	0	0	0	0	0	0
102153	403633	2095	Generator				0	0	0	0	0	0	0	0	0
138267	421271	2083	Generator				0	0	0	0	0	0	0	0	0
138267	438902	2083	Generator				0	0	0	0	0	0	0	0	0
65818	422450	1737	Generator				0	0	0	0	0	0	0	0	0
7796	391786	1468	Generator				0	0	0	0	0	0	0	0	0
77033	400718	1468	Generator				0	0	0	0	0	0	0	0	0
109524	413078	1468	Generator				0	0	0	0	0	0	0	0	0
62589	415988	1468	Generator				0	0	0	0	0	0	0	0	0
129827	426299	1468	Generator				0	0	0	0	0	0	0	0	0
Non-Biogas, Non-RECLAIM, BACT, Lean, <1000															
7814	412278	898	Generator				0	0	0	0	0	0	0	0	0
132087	399874	880	Other				20	0	0	0	0	20.1	0	0	0
132087	399876	880	Other				0	0	0	0	0	0	0	0	0
Non-Biogas, Non-RECLAIM, Non-BACT, Rich, =>1000															
14437	288133	1200	Generator	Upgrade			0	0	0	0	0	0	0	0	0

Table B-2 (Continued)
PAR1110.2 - Energy Analysis

Facility ID No.	Appl. No.	Engine HP	Engine Use	(d)(1)(B) Reduced Limits, 500+ HP 7/1/10	(d)(1)(B) Reduced Limits <500 HP 7/1/11	(d)(1)(C) Reduced Limits Biogas 7/1/12	Electric Use CEMS, MW-hr/yr	Electric Use Engine, MW-hr/yr	Electric Use Cat Ox, MW-hr/yr	Electric Use Cat Ox, MW-hr/yr	Electric Use SCR, MW-hr/yr	Electric Total, MW-hr/yr	Natural Gas Electric, MMscf/yr	Natural Gas Cat Ox, MMscf/yr	Natural Gas SCR, MMscf/yr
14437	288134	1200	Generator	Upgrade			0	0	0	0	0	0	0	0	0
14437	341089	1200	Generator	Upgrade			0	0	0	0	0	0	0	0	0
118684	350357	1131	Generator	Upgrade			0	0	0	0	0	0	0	0	0
118684	350358	1131	Generator	Upgrade			0	0	0	0	0	0	0	0	0
Non-Biogas, Non-RECLAIM, Non-BACT, Rich, <1000															
42218	117607	930	Generator	Upgrade			20	0	0	0	0	20.1	0	0	0
42218	117608	930	Generator	Upgrade			0	0	0	0	0	0	0	0	0
42217	117609	930	Generator	Upgrade			0	0	0	0	0	0	0	0	0
013088	414452	930	Generator	Upgrade			20	0	0	0	0	20.1	0	0	0
142517	438239	713	Generator	Upgrade			0	0	0	0	0	0	0	0	0
85339	274452	315	Generator		Upgrade		0	0	0	0	0	0	0	0	0
86055	279345	294	Generator		Upgrade		0	0	0	0	0	0	0	0	0
20231	281005	150	Generator		Upgrade		20	0	0	0	0	20.1	0	0	0
20231	281006	150	Generator		Upgrade		0	0	0	0	0	0	0	0	0
10636	316911	148	Generator		Upgrade		0	0	0	0	0	0	0	0	0
6728	316912	148	Generator		Upgrade		0	0	0	0	0	0	0	0	0
18435	316913	148	Generator		Upgrade		0	0	0	0	0	0	0	0	0
2638	172356	145	Generator		Upgrade		0	0	0	0	0	0	0	0	0
79856	328255	145	Generator		Upgrade		0	0	0	0	0	0	0	0	0
140598	429420	135	Generator		Upgrade		0	0	0	0	0	0	0	0	0
82303	329294	94	Generator		Upgrade		0	0	0	0	0	0	0	0	0
33465	313771	86	Generator		Upgrade		0	0	0	0	0	0	0	0	0
660	442592	600	Compressor	Upgrade			20	0	0	0	0	20.1	0	0	0
660	442593	600	Compressor	Upgrade			0	0	0	0	0	0	0	0	0
660	442594	600	Compressor	Upgrade			0	0	0	0	0	0	0	0	0
019159	416831	330	Compressor		Upgrade		20	0	0	0	0	20.1	0	0	0
113251	410103	250	Compressor		Upgrade		0	0	0	0	0	0	0	0	0
007417	411022	225	Compressor		Upgrade		20	0	0	0	0	20.1	0	0	0
007417	411023	225	Compressor		Upgrade		0	0	0	0	0	0	0	0	0
007417	411024	225	Compressor		Upgrade		0	0	0	0	0	0	0	0	0
10827	280612	145	Compressor		Upgrade		0	0	0	0	0	0	0	0	0
78802	280570	400	Other		Upgrade		0	0	0	0	0	0	0	0	0
62851	322538	94	Other		Upgrade		0	0	0	0	0	0	0	0	0
65818	311320	810	Pump	Upgrade			20	0	0	0	0	20.1	0	0	0
076581	220569	660	Pump	Upgrade			20	0	0	0	0	20.1	0	0	0
95318	281245	634	Pump	Upgrade			20	0	0	0	0	20.1	0	0	0
95318	281247	634	Pump	Upgrade			0	0	0	0	0	0	0	0	0

Table B-2 (Continued)
PAR1110.2 - Energy Analysis

Facility ID No.	Appl. No.	Engine HP	Engine Use	(d)(1)(B) Reduced Limits, 500+ HP 7/1/10	(d)(1)(B) Reduced Limits <500 HP 7/1/11	(d)(1)(C) Reduced Limits Biogas 7/1/12	Electric Use CEMS, MW-hr/yr	Electric Use Engine, MW-hr/yr	Electric Use Cat Ox, MW-hr/yr	Electric Use Cat Ox, MW-hr/yr	Electric Use SCR, MW-hr/yr	Electric Total, MW-hr/yr	Natural Gas Electric, MMscf/yr	Natural Gas Cat Ox, MMscf/yr	Natural Gas SCR, MMscf/yr
95318	281251	634	Pump	Upgrade			0	0	0	0	0	0	0	0	0
95318	281254	634	Pump	Upgrade			0	0	0	0	0	0	0	0	0
95318	281257	634	Pump	Upgrade			0	0	0	0	0	0	0	0	0
95318	281260	634	Pump	Upgrade			0	0	0	0	0	0	0	0	0
95066	280183	594	Pump	Upgrade			0	0	0	0	0	0	0	0	0
94967	280194	594	Pump	Upgrade			0	0	0	0	0	0	0	0	0
48820	159531	581	Pump	Upgrade			0	0	0	0	0	0	0	0	0
77388	426136	525	Pump	Upgrade			20	0	0	0	0	20.1	0	0	0
77388	426144	525	Pump	Upgrade			0	0	0	0	0	0	0	0	0
77388	426145	525	Pump	Upgrade			0	0	0	0	0	0	0	0	0
103070	312478	512	Pump	Upgrade			0	0	0	0	0	0	0	0	0
68143	187169	500	Pump	Upgrade			0	0	0	0	0	0	0	0	0
103052	390939	500	Pump	Upgrade			0	0	0	0	0	0	0	0	0
070296	411474	500	Pump	Upgrade			20	0	0	0	0	20.1	0	0	0
076581	220570	450	Pump		Upgrade		20	0	0	0	0	20.1	0	0	0
95977	281266	427	Pump		Upgrade		0	0	0	0	0	0	0	0	0
070282	375501	425	Pump		Upgrade		0	0	0	0	0	0	0	0	0
070286	410481	425	Pump		Upgrade		0	0	0	0	0	0	0	0	0
070292	425052	425	Pump		Upgrade		20	0	0	0	0	20.1	0	0	0
15748	280342	417	Pump		Upgrade		20	0	0	0	0	20.1	0	0	0
15748	280344	417	Pump		Upgrade		0	0	0	0	0	0	0	0	0
20231	435450	409	Pump		Upgrade		20	0	0	0	0	20.1	0	0	0
20231	435451	409	Pump		Upgrade		0	0	0	0	0	0	0	0	0
94950	280975	400	Pump		Upgrade		0	0	0	0	0	0	0	0	0
53733	280999	395	Pump		Upgrade		0	0	0	0	0	0	0	0	0
24427	281000	395	Pump		Upgrade		0	0	0	0	0	0	0	0	0
95535	281109	395	Pump		Upgrade		0	0	0	0	0	0	0	0	0
21104	407532	395	Pump		Upgrade		20	0	0	0	0	20.1	0	0	0
65818	311322	370	Pump		Upgrade		20	0	0	0	0	20.1	0	0	0
58639	435736	370	Pump		Upgrade		20	0	0	0	0	20.1	0	0	0
74396	280341	369	Pump		Upgrade		0	0	0	0	0	0	0	0	0
070292	214307	330	Pump		Upgrade		20	0	0	0	0	20.1	0	0	0
070292	214308	330	Pump		Upgrade		0	0	0	0	0	0	0	0	0
070282	256758	330	Pump		Upgrade		0	0	0	0	0	0	0	0	0
070311	267082	330	Pump		Upgrade		0	0	0	0	0	0	0	0	0
019159	367167	330	Pump		Upgrade		20	0	0	0	0	20.1	0	0	0
019159	367168	330	Pump		Upgrade		0	0	0	0	0	0	0	0	0
070290	367776	330	Pump		Upgrade		0	0	0	0	0	0	0	0	0

Table B-2 (Continued)
PAR1110.2 - Energy Analysis

Facility ID No.	Appl. No.	Engine HP	Engine Use	(d)(1)(B) Reduced Limits, 500+ HP 7/1/10	(d)(1)(B) Reduced Limits <500 HP 7/1/11	(d)(1)(C) Reduced Limits Biogas 7/1/12	Electric Use CEMS, MW-hr/yr	Electric Use Engine, MW-hr/yr	Electric Use Cat Ox, MW-hr/yr	Electric Use Cat Ox, MW-hr/yr	Electric Use SCR, MW-hr/yr	Electric Total, MW-hr/yr	Natural Gas Electric, MMscf/yr	Natural Gas Cat Ox, MMscf/yr	Natural Gas SCR, MMscf/yr
070296	390974	330	Pump		Upgrade		20	0	0	0	0	20	0	0	0
21104	414791	330	Pump		Upgrade		20	0	0	0	0	20	0	0	0
21104	436827	330	Pump		Upgrade		0	0	0	0	0	0	0	0	0
21104	436828	330	Pump		Upgrade		0	0	0	0	0	0	0	0	0
21104	436829	330	Pump		Upgrade		0	0	0	0	0	0	0	0	0
21104	436830	330	Pump		Upgrade		0	0	0	0	0	0	0	0	0
52348	276622	318	Pump		Upgrade		0	0	0	0	0	0	0	0	0
52348	276625	318	Pump		Upgrade		0	0	0	0	0	0	0	0	0
52348	276627	318	Pump		Upgrade		0	0	0	0	0	0	0	0	0
103052	170492	300	Pump		Upgrade		0	0	0	0	0	0	0	0	0
070305	267083	300	Pump		Upgrade		0	0	0	0	0	0	0	0	0
94940	280974	283	Pump		Upgrade		0	0	0	0	0	0	0	0	0
83315	280968	280	Pump		Upgrade		0	0	0	0	0	0	0	0	0
83315	280969	280	Pump		Upgrade		0	0	0	0	0	0	0	0	0
83315	280970	280	Pump		Upgrade		0	0	0	0	0	0	0	0	0
132190	264164	275	Pump		Upgrade		0	0	0	0	0	0	0	0	0
83313	280967	270	Pump		Upgrade		0	0	0	0	0	0	0	0	0
18239	328539	265	Pump		Upgrade		0	0	0	0	0	0	0	0	0
18239	328540	265	Pump		Upgrade		0	0	0	0	0	0	0	0	0
94998	280360	250	Pump		Upgrade		0	0	0	0	0	0	0	0	0
94999	280365	250	Pump		Upgrade		0	0	0	0	0	0	0	0	0
95000	280369	250	Pump		Upgrade		0	0	0	0	0	0	0	0	0
83312	280965	250	Pump		Upgrade		0	0	0	0	0	0	0	0	0
83312	280966	250	Pump		Upgrade		0	0	0	0	0	0	0	0	0
83318	280971	250	Pump		Upgrade		0	0	0	0	0	0	0	0	0
84162	306922	238	Pump		Upgrade		0	0	0	0	0	0	0	0	0
84162	245380	230	Pump		Upgrade		0	0	0	0	0	0	0	0	0
52885	245384	230	Pump		Upgrade		0	0	0	0	0	0	0	0	0
52885	245385	230	Pump		Upgrade		0	0	0	0	0	0	0	0	0
94442	274654	230	Pump		Upgrade		0	0	0	0	0	0	0	0	0
11301	215041	225	Pump		Upgrade		20	0	0	0	0	20.1	0	0	0
11301	215043	225	Pump		Upgrade		0	0	0	0	0	0	0	0	0
070295	267086	225	Pump		Upgrade		0	0	0	0	0	0	0	0	0
11301	311565	225	Pump		Upgrade		20	0	0	0	0	20.1	0	0	0
11301	311566	225	Pump		Upgrade		0	0	0	0	0	0	0	0	0
070300	335327	225	Pump		Upgrade		0	0	0	0	0	0	0	0	0
070292	368326	225	Pump		Upgrade		20	0	0	0	0	20.1	0	0	0

Table B-2 (Continued)
PAR1110.2 - Energy Analysis

Facility ID No.	Appl. No.	Engine HP	Engine Use	(d)(1)(B) Reduced Limits, 500+ HP 7/1/10	(d)(1)(B) Reduced Limits <500 HP 7/1/11	(d)(1)(C) Reduced Limits Biogas 7/1/12	Electric Use CEMS, MW-hr/yr	Electric Use Engine, MW-hr/yr	Electric Use Cat Ox, MW-hr/yr	Electric Use Cat Ox, MW-hr/yr	Electric Use SCR, MW-hr/yr	Electric Total, MW-hr/yr	Natural Gas Electric, MMscf/yr	Natural Gas Cat Ox, MMscf/yr	Natural Gas SCR, MMscf/yr
070304	388598	225	Pump		Upgrade		0	0	0	0	0	0.00	0	0	0
070290	390942	225	Pump		Upgrade		0	0	0	0	0	0.00	0	0	0
070296	390946	225	Pump		Upgrade		20	0	0	0	0	20.1	0	0	0
15748	280343	220	Pump		Upgrade		20	0	0	0	0	20.1	0	0	0
070298	267085	200	Pump		Upgrade		0	0	0	0	0	0	0	0	0
070280	267096	200	Pump		Upgrade		0	0	0	0	0	0	0	0	0
070295	375503	200	Pump		Upgrade		0	0	0	0	0	0	0	0	0
070302	402959	200	Pump		Upgrade		0	0	0	0	0	0	0	0	0
070300	433992	200	Pump		Upgrade		0	0	0	0	0	0	0	0	0
070300	433993	200	Pump		Upgrade		0	0	0	0	0	0	0	0	0
070300	433994	200	Pump		Upgrade		0	0	0	0	0	0	0	0	0
2924	264159	190	Pump		Upgrade		0	0	0	0	0	0	0	0	0
94938	280976	186	Pump		Upgrade		0	0	0	0	0	0	0	0	0
94937	280978	186	Pump		Upgrade		0	0	0	0	0	0	0	0	0
94937	280980	186	Pump		Upgrade		0	0	0	0	0	0	0	0	0
94937	280981	186	Pump		Upgrade		0	0	0	0	0	0	0	0	0
94995	280355	180	Pump		Upgrade		0	0	0	0	0	0	0	0	0
94998	280359	180	Pump		Upgrade		0	0	0	0	0	0	0	0	0
94997	280362	180	Pump		Upgrade		0	0	0	0	0	0	0	0	0
94999	280364	180	Pump		Upgrade		0	0	0	0	0	0	0	0	0
95979	281236	180	Pump		Upgrade		20	0	0	0	0	20.1	0	0	0
95979	281237	180	Pump		Upgrade		0	0	0	0	0	0	0	0	0
95979	281240	180	Pump		Upgrade		0	0	0	0	0	0	0	0	0
95979	281241	180	Pump		Upgrade		0	0	0	0	0	0	0	0	0
132189	264161	175	Pump		Upgrade		0	0	0	0	0	0	0	0	0
72489	288630	172	Pump		Upgrade		0	0	0	0	0	0	0	0	0
72489	288631	172	Pump		Upgrade		0	0	0	0	0	0	0	0	0
72489	288632	172	Pump		Upgrade		0	0	0	0	0	0	0	0	0
81001	246340	170	Pump		Upgrade		0	0	0	0	0	0	0	0	0
070284	267090	165	Pump		Upgrade		0	0	0	0	0	0	0	0	0
070284	267091	165	Pump		Upgrade		0	0	0	0	0	0	0	0	0
2868	274540	157	Pump		Upgrade		0	0	0	0	0	0	0	0	0
2868	279544	157	Pump		Upgrade		0	0	0	0	0	0	0	0	0
66403	279545	157	Pump		Upgrade		0	0	0	0	0	0	0	0	0
66403	279546	157	Pump		Upgrade		0	0	0	0	0	0	0	0	0
66413	279547	157	Pump		Upgrade		0	0	0	0	0	0	0	0	0
94928	280632	150	Pump		Upgrade		0	0	0	0	0	0	0	0	0

Table B-2 (Continued)
PAR1110.2 - Energy Analysis

Facility ID No.	Appl. No.	Engine HP	Engine Use	(d)(1)(B) Reduced Limits, 500+ HP 7/1/10	(d)(1)(B) Reduced Limits <500 HP 7/1/11	(d)(1)(C) Reduced Limits Biogas 7/1/12	Electric Use CEMS, MW-hr/yr	Electric Use Engine, MW-hr/yr	Electric Use Cat Ox, MW-hr/yr	Electric Use Cat Ox, MW-hr/yr	Electric Use SCR, MW-hr/yr	Electric Total, MW-hr/yr	Natural Gas Electric, MMscf/yr	Natural Gas Cat Ox, MMscf/yr	Natural Gas SCR, MMscf/yr
94928	280633	150	Pump		Upgrade		0	0	0	0	0	0	0	0	0
20231	281023	150	Pump		Upgrade		20	0	0	0	0	20.1	0	0	0
20231	281024	150	Pump		Upgrade		0	0	0	0	0	0	0	0	0
070317	267076	145	Pump		Upgrade		0	0	0	0	0	0	0	0	0
070299	267084	145	Pump		Upgrade		0	0	0	0	0	0	0	0	0
070283	267094	145	Pump		Upgrade		0	0	0	0	0	0	0	0	0
66413	279624	145	Pump		Upgrade		0	0	0	0	0	0	0	0	0
66413	311099	145	Pump		Upgrade		0	0	0	0	0	0	0	0	0
66413	311100	145	Pump		Upgrade		0	0	0	0	0	0	0	0	0
070313	328532	145	Pump		Upgrade		0	0	0	0	0	0	0	0	0
070281	393971	145	Pump		Upgrade		0	0	0	0	0	0	0	0	0
136235	414451	145	Pump		Upgrade		0	0	0	0	0	0	0	0	0
070293	436931	145	Pump		Upgrade		0	0	0	0	0	0	0	0	0
95979	281242	144	Pump		Upgrade		20	0	0	0	0	20.1	0	0	0
95979	281243	144	Pump		Upgrade		0	0	0	0	0	0	0	0	0
52883	245374	143	Pump		Upgrade		0	0	0	0	0	0	0	0	0
52883	245375	143	Pump		Upgrade		0	0	0	0	0	0	0	0	0
070307	267080	140	Pump		Upgrade		0	0	0	0	0	0	0	0	0
95000	280367	140	Pump		Upgrade		0	0	0	0	0	0	0	0	0
95067	280185	137	Pump		Upgrade		0	0	0	0	0	0	0	0	0
95067	280190	137	Pump		Upgrade		0	0	0	0	0	0	0	0	0
95067	280191	137	Pump		Upgrade		0	0	0	0	0	0	0	0	0
52884	245388	121	Pump		Upgrade		0	0	0	0	0	0	0	0	0
96374	280786	116	Pump		Upgrade		0	0	0	0	0	0	0	0	0
96374	280788	116	Pump		Upgrade		0	0	0	0	0	0	0	0	0
96374	280790	116	Pump		Upgrade		0	0	0	0	0	0	0	0	0
3513	399707	109	Pump		Upgrade		20	0	0	0	0	20.1	0	0	0
3513	399708	109	Pump		Upgrade		0	0	0	0	0	0	0	0	0
3513	399709	109	Pump		Upgrade		0	0	0	0	0	0	0	0	0
71685	280685	100	Pump		Upgrade		0	0	0	0	0	0	0	0	0
65819	311321	99	Pump		Upgrade		0	0	0	0	0	0	0	0	0
070295	241359	95	Pump		Upgrade		0	0	0	0	0	0	0	0	0
20231	281016	75	Pump		Upgrade		20	0	0	0	0	20.1	0	0	0
20231	281021	75	Pump		Upgrade		0	0	0	0	0	0	0	0	0
48523	288615	61	Pump		Upgrade		0	0	0	0	0	0	0	0	0
48523	288616	61	Pump		Upgrade		0	0	0	0	0	0	0	0	0

Table B-2 (Continued)
PAR1110.2 - Energy Analysis

Facility ID No.	Appl. No.	Engine HP	Engine Use	(d)(1)(B) Reduced Limits, 500+ HP 7/1/10	(d)(1)(B) Reduced Limits <500 HP 7/1/11	(d)(1)(C) Reduced Limits Biogas 7/1/12	Electric Use CEMS, MW-hr/yr	Electric Use Engine, MW-hr/yr	Electric Use Cat Ox, MW-hr/yr	Electric Use Cat Ox, MW-hr/yr	Electric Use SCR, MW-hr/yr	Electric Total, MW-hr/yr	Natural Gas Electric, MMscf/yr	Natural Gas Cat Ox, MMscf/yr	Natural Gas SCR, MMscf/yr
48523	288617	61	Pump		Upgrade		0	0	0	0	0	0	0	0	0
Survey Total							1,975	163,091	3	6	1,581	166,656	-1,718	2.0	152
District Total							2,837	234,326	5	9	2,272	239,448	-2,469	2.9	218

Control Measure

<u>Install NOx-CO CEMS (CEMS) (costs are for one CEMS serving one or more engines)--Life=20 yrs</u>

Power use by sample pump, refrigeration condenser and climate control (2,300 W x 8,760 op hr/yr), 2,300 W from Power Systems estimate provided to Dr. Howard Lange, April 12, 2007..

<u>Upgrade Three-Way Catalyst (Upgrade)--NAIC=421730, Life=3 yrs</u>

For estimate: 1-in. H2O pressure drop, if generator, electrical production decrease, kWh/yr = 0.00074 parasitic factor*bhp*8,000 op hr/yr*0.746 kW/bhp*0.97 motor efficiency OR if work engine, increased natural gas use by plant, scf/yr = (0.00074 parasitic factor*bhp*8, 000 op hr/yr*2545 Btu/bhp)/0.31 motor efficiency/1,020 Btu/scf.

<u>Remove Engine and Replace with Electric Motor (generator engines not replaced) (Electric)--, Life=30 yrs (motor)</u>

Reduced natural gas use, SCF/yr = (bhp*8, 000 op hr/yr *2,545 Btu/bhp) /0.31 motor efficiency/1,020 Btu/scf but corresponding increase in grid power production if this engine drives a generator kWh/yr = (bhp*8, 000 op-hr/yr *0.97 motor efficiency *0.746 kW/bhp

Increased power use (if non-generator), kWh/yr= (bph*8, 000 op hr/yr)/0.97 motor efficiency *0.746 kW/bhp

<u>Install fuel gas cleanup system and SCR (SCR)--Life=30 yrs, Mntnc=replace sorbent monthly and catalysts (2) every 3 yrs</u>

(Catalyst volume & weight.--1 CF per MMBtu/hr [includes ox cat], 1.2 specific gravity. Total cat volume, weight per HP = 14.2 cubic in, 0.615 lb)

For est. pressure drops of 3-in. H2O in cleanup system and 3-in. H2O in SCR+catox system, if generator, electrical production decrease, kWh/yr = 0.00236 parasitic factor * bhp*8, 000 op hr/yr *0.97 motor efficiency *0.746 kW/bhp OR if work engine, increase natural gas use by plant, scf/yr = (0.00236 parasitic factor*bhp*8, 000 op hr/yr *2,545 Btu/bhp)/0.31 motor efficiency/1,020 Btu/scf.

Table B-3
Hanover Engine Energy Analysis

Facility ID No.	Appl. No.	Engine HP	Engine Use	Primary Fuel	Natural Gas Usage, MMcft/yr	Natural Gas Energy, MMBtu/yr	Electric Energy, MW-hr/yr
43880	434981	1,050	Compressor	Natural Gas	15.91	16,233	6,078
43880	434982	1,050	Compressor	Natural Gas	13.84	14,121	6,078
43880	434983	1,050	Compressor	Natural Gas	13.84	14,121	6,078
43759	434971	800	Compressor	Natural Gas	12.16	12,407	4,631
43759	434972	800	Compressor	Natural Gas	12.16	12,407	4,631
43759	434973	800	Compressor	Natural Gas	12.16	12,407	4,631
22265	434975	800	Compressor	Natural Gas	10.64	10,857	4,631
22265	434976	800	Compressor	Natural Gas	10.64	10,857	4,631
22265	434977	800	Compressor	Natural Gas	10.64	10,857	4,631
18517	434978	530	Compressor	Natural Gas	8.98	9,157	3,068
18517	434979	530	Compressor	Natural Gas	8.98	9,157	3,068
18517	434980	530	Compressor	Natural Gas	8.98	9,157	3,068
					139	141,739	55,227

Remove Engine and Replace with Electric Motor (generator engines not replaced) (Electric)-- (motor), Life=30 yrs (motor)

Reduced natural gas use, SCF/yr = (bhp*8, 000 op hr/yr *2,545 Btu/bhp) /0.31 motor efficiency/1,020 Btu/scf but corresponding increase in grid power production if this engine drives a generator kWh/yr = (bhp*8, 000 op-hr/yr *0.97 motor efficiency *0.746 kW/bhp

Table B-4
PAR1110.2 - Solid and Hazardous Waste Estimates

Facility ID No.	Appl. No.	Engine HP	Engine Use	(d)(1)(B) Reduced Limits, 500+ HP 7/1/10	(d)(1)(B) Reduced Limits <500 HP 7/1/11	(d)(1)(C) Reduced Limits Biogas 7/1/12	Electric Engine, lb	New Cat Ox, lb	Upgrade Cat Ox, lb	SCR Cat, lb
Biogas, BACT, =>1000										
025070	394362	4261	Generator			SCR	0	0	0	2,131
025070	394363	4261	Generator			SCR	0	0	0	2,131
025070	394364	4261	Generator			SCR	0	0	0	2,131
9163	323773	1988	Generator			SCR	0	0	0	994
9163	323774	1988	Generator			SCR	0	0	0	994
113674	430422	1877	Generator			SCR	0	0	0	939
113674	430424	1877	Generator			SCR	0	0	0	939
113674	430726	1877	Generator			SCR	0	0	0	939
50310	437561	1877	Generator			SCR	0	0	0	939
50310	437562	1877	Generator			SCR	0	0	0	939
50310	437563	1877	Generator			SCR	0	0	0	939
50310	437564	1877	Generator			SCR	0	0	0	939
50310	437565	1877	Generator			SCR	0	0	0	939
6979	438643	1777	Generator			SCR	0	0	0	889
140846	430412	1468	Generator			SCR	0	0	0	734
74413	390032	1350	Generator			SCR	0	0	0	675
Biogas, BACT, <1000										
013088	414294	400	Compressor			SCR	0	0	0	200
Biogas, Non-BACT, =>10000										
104806	323139	4235	Generator			SCR	0	0	0	2,118
104806	323140	4235	Generator			SCR	0	0	0	2,118
29110	414653	4166	Generator			SCR	0	0	0	2,083
29110	414654	4166	Generator			SCR	0	0	0	2,083
29110	414655	4166	Generator			SCR	0	0	0	2,083
29110	414656	4166	Generator			SCR	0	0	0	2,083
29110	414657	4166	Generator			SCR	0	0	0	2,083
17301	414648	3471	Generator			SCR	0	0	0	1,736
17301	414650	3471	Generator			SCR	0	0	0	1,736
17301	414651	3471	Generator			SCR	0	0	0	1,736
113518	414941	2650	Generator			SCR	0	0	0	1,325
113518	414942	2650	Generator			SCR	0	0	0	1,325
113518	414943	2650	Generator			SCR	0	0	0	1,325

Table B-4 (Continued)
PAR1110.2 - Solid and Hazardous Waste Estimates

Facility ID No.	Appl. No.	Engine HP	Engine Use	(d)(1)(B) Reduced Limits, 500+ HP 7/1/10	(d)(1)(B) Reduced Limits <500 HP 7/1/11	(d)(1)(C) Reduced Limits Biogas 7/1/12	Electric Engine, lb	New Cat Ox, lb	Upgrade Cat Ox, lb	SCR Cat, lb
142408	437742	2650	Generator			SCR	0	0	0	1,325
142408	437743	2650	Generator			SCR	0	0	0	1,325
142408	437744	2650	Generator			SCR	0	0	0	1,325
142408	437745	2650	Generator			SCR	0	0	0	1,325
142408	437746	2650	Generator			SCR	0	0	0	1,325
142417	437754	2650	Generator			SCR	0	0	0	1,325
142417	437755	2650	Generator			SCR	0	0	0	1,325
9961	301547	1599	Generator			SCR	0	0	0	800
9961	301548	1599	Generator			SCR	0	0	0	800
9961	301549	1599	Generator			SCR	0	0	0	800
135216	411148	1408	Generator			SCR	0	0	0	704
135216	411147	1158	Generator			SCR	0	0	0	579
Biogas, Non-BACT <1000										
9163	433835	920	Generator			SCR	0	0	0	460
1179	438072	911	Generator			SCR	0	0	0	456
11301	160410	750	Generator			SCR	0	0	0	375
11301	160411	750	Generator			SCR	0	0	0	375
022674	351750	705	Generator			SCR	0	0	0	353
13433	319394	580	Generator			SCR	0	0	0	290
13433	319395	580	Generator			SCR	0	0	0	290
13433	319396	580	Generator			SCR	0	0	0	290
3866	172772	636	Compressor			SCR	0	0	0	318
001703	373739	530	Compressor			SCR	0	0	0	265
001703	373740	530	Compressor			SCR	0	0	0	265
019159	416944	260	Compressor			SCR	0	0	0	130
Non-Biogas, RECLAIM, BACT, Rich, Major										
68118	436966	2000	Pump				0	0	0	0
Non-Biogas, RECLAIM, BACT, Rich, Non-Major										
800128	367656	818	Generator				0	0	0	0
800128	367657	818	Generator				0	0	0	0
800128	367658	818	Generator				0	0	0	0
800128	367659	818	Generator				0	0	0	0
18455	406950	600	Generator				0	0	0	0

Table B-4 (Continued)
PAR1110.2 - Solid and Hazardous Waste Estimates

Facility ID No.	Appl. No.	Engine HP	Engine Use	(d)(1)(B) Reduced Limits, 500+ HP 7/1/10	(d)(1)(B) Reduced Limits <500 HP 7/1/11	(d)(1)(C) Reduced Limits Biogas 7/1/12	Electric Engine, lb	New Cat Ox, lb	Upgrade Cat Ox, lb	SCR Cat, lb
18455	406951	564	Generator				0	0	0	0
18455	406952	564	Generator				0	0	0	0
141012	432686	790	Compressor				0	0	0	0
141012	432687	790	Compressor				0	0	0	0
800127	274839	750	Compressor				0	0	0	0
346	335791	545	Compressor				0	0	0	0
100844	425811	412	Compressor				0	0	0	0
6714	408065	283	Pump				0	0	0	0
6714	408067	283	Pump				0	0	0	0
6714	408064	116	Pump				0	0	0	0
6714	408068	116	Pump				0	0	0	0
Non-Biogas, RECLAIM, Non-BACT, Rich, Major										
130211	414383	2068	Generator	Upgrade			0	0	83	0
Non-Biogas, RECLAIM, Non-BACT, Rich, Non-Major										
98159	332851	870	Generator	Upgrade			0	0	35	0
5973	362357	818	Generator	Upgrade			0	0	33	0
5973	362358	818	Generator	Upgrade			0	0	33	0
5973	362359	818	Generator	Upgrade			0	0	33	0
54547	171158	125	Generator		Upgrade		0	0	5.0	0
5973	101703	738	Compressor	Upgrade			0	0	30	0
5973	101704	738	Compressor	Upgrade			0	0	30	0
75531	319404	250	Compressor		Upgrade		0	0	10	0
75531	319405	250	Compressor		Upgrade		0	0	10	0
11034	190074	132	Compressor		Upgrade		0	0	5.3	0
11034	190075	132	Compressor		Upgrade		0	0	5.3	0
11034	190076	132	Compressor		Upgrade		0	0	5.3	0
800189	457331	708	Pump	Upgrade			0	0	28	0
800189	457332	708	Pump	Upgrade			0	0	28	0
11034	156967	377	Pump		Upgrade		0	0	15	0
11034	156968	377	Pump		Upgrade		0	0	15	0
9053	434478	377	Pump		Upgrade		0	0	15	0
9053	434498	377	Pump		Upgrade		0	0	15	0
9053	434501	377	Pump		Upgrade		0	0	15	0

Table B-4 (Continued)
PAR1110.2 - Solid and Hazardous Waste Estimates

Facility ID No.	Appl. No.	Engine HP	Engine Use	(d)(1)(B) Reduced Limits, 500+ HP 7/1/10	(d)(1)(B) Reduced Limits <500 HP 7/1/11	(d)(1)(C) Reduced Limits Biogas 7/1/12	Electric Engine, lb	New Cat Ox, lb	Upgrade Cat Ox, lb	SCR Cat, lb
11034	156966	287	Pump		Upgrade		0	0	11	0
9053	434502	244	Pump		Upgrade		0	0	10	0
9053	434503	244	Pump		Upgrade		0	0	10	0
9053	434504	244	Pump		Upgrade		0	0	10	0
800189	457324	218	Pump		Upgrade		0	0	8.7	0
800189	457335	218	Pump		Upgrade		0	0	8.7	0
11034	190071	193	Pump		Upgrade		0	0	7.7	0
11034	190072	193	Pump		Upgrade		0	0	7.7	0
11034	190073	193	Pump		Upgrade		0	0	7.7	0
800189	457334	151	Pump		Upgrade		0	0	6.0	0
800189	457325	102	Pump		Upgrade		0	0	4.1	0
800189	457326	102	Pump		Upgrade		0	0	4.1	0
8582	198426	97	Pump		Upgrade		0	0	3.9	0
8582	198427	97	Pump		Upgrade		0	0	3.9	0
8582	198428	97	Pump		Upgrade		0	0	3.9	0
9217	196405	86	Pump		Upgrade		0	0	3.4	0
9217	196409	86	Pump		Upgrade		0	0	3.4	0
Non-Biogas, RECLAIM, Non-BACT, Lean, Major, 4-Stroke										
5973	147546	5500	Compressor	Ox Cat			0	220	0	0
5973	156060	5500	Compressor	Ox Cat			0	220	0	0
5973	156061	5500	Compressor	Ox Cat			0	220	0	0
5973	156062	5500	Compressor	Ox Cat			0	220	0	0
5973	156063	5500	Compressor	Ox Cat			0	220	0	0
800128	153507	2000	Compressor	Ox Cat			0	80	0	0
800128	159101	2000	Compressor	Ox Cat			0	80	0	0
800128	159102	2000	Compressor	Ox Cat			0	80	0	0
800128	159103	2000	Compressor	Ox Cat			0	80	0	0
800128	159104	2000	Compressor	Ox Cat			0	80	0	0
9053	434505	1650	Compressor	Ox Cat			0	66	0	0
9053	434506	1650	Compressor	Ox Cat			0	66	0	0
9053	434507	1650	Compressor	Ox Cat			0	66	0	0
Non-Biogas, RECLAIM, Non-BACT, Lean, Major, 2-Stroke										
4242	170675	3000	Generator	Electric			14,000	0	0	0

Table B-4 (Continued)
PAR1110.2 - Solid and Hazardous Waste Estimates

Facility ID No.	Appl. No.	Engine HP	Engine Use	(d)(1)(B) Reduced Limits, 500+ HP 7/1/10	(d)(1)(B) Reduced Limits <500 HP 7/1/11	(d)(1)(C) Reduced Limits Biogas 7/1/12	Electric Engine, lb	New Cat Ox, lb	Upgrade Cat Ox, lb	SCR Cat, lb
8582	368116	2000	Compressor	Electric			14,000	0	0	0
8582	368117	2000	Compressor	Electric			14,000	0	0	0
8582	368118	2000	Compressor	Electric			14,000	0	0	0
4242	169829	3200	Compressor	Electric			14,000	0	0	0
4242	172126	3000	Compressor	Electric			14,000	0	0	0
800127	327697	1800	Compressor	Electric			14,000	0	0	0
800127	327699	1800	Compressor	Electric			14,000	0	0	0
8582	311760	1350	Compressor	Electric			14,000	0	0	0
8582	311761	1350	Compressor	Electric			14,000	0	0	0
8582	311755	1100	Compressor	Electric			14,000	0	0	0
8582	311756	1100	Compressor	Electric			14,000	0	0	0
4242	364371	995	Compressor	Electric			14,000	0	0	0
4242	364373	995	Compressor	Electric			14,000	0	0	0
4242	364374	995	Compressor	Electric			14,000	0	0	0
Non-Biogas, RECLAIM, Non-BACT, Lean, Non-Major										
17953	384810	810	Generator	Ox Cat			0	32	0	0
800127	169969	328	Generator		Ox Cat		0	0	0	0
800127	169970	328	Generator		Ox Cat		0	0	0	0
800127	169971	328	Generator		Ox Cat		0	0	0	0
800127	169972	328	Generator		Ox Cat		0	0	0	0
101369	292228	88	Generator		Ox Cat		0	0	0	0
800363	347919	300	Compressor		Ox Cat		0	0	0	0
800189	457333	218	Pump		Ox Cat		0	0	0	0
Non-Biogas, Non-RECLAIM, BACT, Rich, =>1000										
007417	409351	2200	Generator				0	0	0	0
11245	406575	2080	Generator				0	0	0	0
11245	406576	2080	Generator				0	0	0	0
11245	406577	2080	Generator				0	0	0	0
132687	401752	1898	Generator				0	0	0	0
132687	401753	1898	Generator				0	0	0	0
129033	388869	1695	Generator				0	0	0	0
129033	388870	1695	Generator				0	0	0	0
129033	388871	1695	Generator				0	0	0	0

Table B-4 (Continued)
PAR1110.2 - Solid and Hazardous Waste Estimates

Facility ID No.	Appl. No.	Engine HP	Engine Use	(d)(1)(B) Reduced Limits, 500+ HP 7/1/10	(d)(1)(B) Reduced Limits <500 HP 7/1/11	(d)(1)(C) Reduced Limits Biogas 7/1/12	Electric Engine, lb	New Cat Ox, lb	Upgrade Cat Ox, lb	SCR Cat, lb
129033	388873	1695	Generator				0	0	0	0
129033	388875	1695	Generator				0	0	0	0
129033	388876	1695	Generator				0	0	0	0
129033	388877	1695	Generator				0	0	0	0
3513	399704	1692	Generator				0	0	0	0
3513	399705	1692	Generator				0	0	0	0
6324	416768	1478	Generator				0	0	0	0
6324	416769	1478	Generator				0	0	0	0
67399	401572	1470	Generator				0	0	0	0
43880	434981	1050	Compressor				0	0	0	0
43880	434982	1050	Compressor				0	0	0	0
43880	434983	1050	Compressor				0	0	0	0
136965	416861	2000	Pump				0	0	0	0
68112	423950	2000	Pump				0	0	0	0
800236	377389	1564	Pump				0	0	0	0
800236	377395	1564	Pump				0	0	0	0
800236	377397	1564	Pump				0	0	0	0
800236	377399	1564	Pump				0	0	0	0
800236	377400	1564	Pump				0	0	0	0
Non-Biogas, Non-RECLAIM, BACT, Rich, <1000										
96326	434798	999	Generator				0	0	0	0
96326	434799	999	Generator				0	0	0	0
1912	408888	998	Generator				0	0	0	0
1912	408889	998	Generator				0	0	0	0
001703	299074	930	Generator				0	0	0	0
001703	331502	930	Generator				0	0	0	0
120088	387989	930	Generator				0	0	0	0
120088	387990	930	Generator				0	0	0	0
121454	387995	930	Generator				0	0	0	0
121454	387996	930	Generator				0	0	0	0
131709	398473	930	Generator				0	0	0	0
45063	396528	840	Generator				0	0	0	0
19185	428146	800	Generator				0	0	0	0

Table B-4 (Continued)
PAR1110.2 - Solid and Hazardous Waste Estimates

Facility ID No.	Appl. No.	Engine HP	Engine Use	(d)(1)(B) Reduced Limits, 500+ HP 7/1/10	(d)(1)(B) Reduced Limits <500 HP 7/1/11	(d)(1)(C) Reduced Limits Biogas 7/1/12	Electric Engine, lb	New Cat Ox, lb	Upgrade Cat Ox, lb	SCR Cat, lb
138723	422556	792	Generator				0	0	0	0
138723	422557	792	Generator				0	0	0	0
58639	390872	791	Generator				0	0	0	0
79174	385862	738	Generator				0	0	0	0
131258	420975	643	Generator				0	0	0	0
99201	421763	585	Generator				0	0	0	0
139280	424326	585	Generator				0	0	0	0
99201	421980	584	Generator				0	0	0	0
19185	428143	543	Generator				0	0	0	0
89159	422466	531	Generator				0	0	0	0
133176	403608	530	Generator				0	0	0	0
133176	403610	530	Generator				0	0	0	0
133176	403611	530	Generator				0	0	0	0
132251	409035	530	Generator				0	0	0	0
132251	409036	530	Generator				0	0	0	0
138293	421366	530	Generator				0	0	0	0
138293	421367	530	Generator				0	0	0	0
138293	421368	530	Generator				0	0	0	0
138851	422959	530	Generator				0	0	0	0
138851	422960	530	Generator				0	0	0	0
141084	431261	530	Generator				0	0	0	0
141084	431262	530	Generator				0	0	0	0
70769	408911	495	Generator				0	0	0	0
140945	430753	380	Generator				0	0	0	0
65819	389615	366	Generator				0	0	0	0
137369	418087	350	Generator				0	0	0	0
118124	417507	336	Generator				0	0	0	0
118124	417508	336	Generator				0	0	0	0
131157	391590	310	Generator				0	0	0	0
131157	391591	310	Generator				0	0	0	0
131157	391592	310	Generator				0	0	0	0
131157	391593	310	Generator				0	0	0	0
131157	391594	310	Generator				0	0	0	0

Table B-4 (Continued)
PAR1110.2 - Solid and Hazardous Waste Estimates

Facility ID No.	Appl. No.	Engine HP	Engine Use	(d)(1)(B) Reduced Limits, 500+ HP 7/1/10	(d)(1)(B) Reduced Limits <500 HP 7/1/11	(d)(1)(C) Reduced Limits Biogas 7/1/12	Electric Engine, lb	New Cat Ox, lb	Upgrade Cat Ox, lb	SCR Cat, lb
131157	391596	310	Generator				0	0	0	0
131157	391597	310	Generator				0	0	0	0
131157	391598	310	Generator				0	0	0	0
131157	391599	310	Generator				0	0	0	0
123684	395143	310	Generator				0	0	0	0
131156	396199	310	Generator				0	0	0	0
131155	396200	310	Generator				0	0	0	0
138279	421318	310	Generator				0	0	0	0
141363	432379	310	Generator				0	0	0	0
143086	438530	310	Generator				0	0	0	0
143086	438531	310	Generator				0	0	0	0
143086	438533	310	Generator				0	0	0	0
143086	438534	310	Generator				0	0	0	0
133802	405959	282	Generator				0	0	0	0
133802	405960	282	Generator				0	0	0	0
133802	405961	282	Generator				0	0	0	0
133802	405962	282	Generator				0	0	0	0
141084	431264	282	Generator				0	0	0	0
129336	389961	275	Generator				0	0	0	0
140947	430760	270	Generator				0	0	0	0
140947	430762	270	Generator				0	0	0	0
140947	430764	270	Generator				0	0	0	0
141199	435531	270	Generator				0	0	0	0
141199	435532	270	Generator				0	0	0	0
141199	435533	270	Generator				0	0	0	0
135490	412041	268	Generator				0	0	0	0
135490	412042	268	Generator				0	0	0	0
135490	412043	268	Generator				0	0	0	0
45938	417562	240	Generator				0	0	0	0
2638	320968	225	Generator				0	0	0	0
2638	320969	225	Generator				0	0	0	0
131426	431200	220	Generator				0	0	0	0
131426	431201	220	Generator				0	0	0	0

Table B-4 (Continued)
PAR1110.2 - Solid and Hazardous Waste Estimates

Facility ID No.	Appl. No.	Engine HP	Engine Use	(d)(1)(B) Reduced Limits, 500+ HP 7/1/10	(d)(1)(B) Reduced Limits <500 HP 7/1/11	(d)(1)(C) Reduced Limits Biogas 7/1/12	Electric Engine, lb	New Cat Ox, lb	Upgrade Cat Ox, lb	SCR Cat, lb
130085	392437	210	Generator				0	0	0	0
134448	408357	210	Generator				0	0	0	0
134449	408359	210	Generator				0	0	0	0
138055	420563	210	Generator				0	0	0	0
138056	420564	210	Generator				0	0	0	0
140466	428824	210	Generator				0	0	0	0
82513	433441	202	Generator				0	0	0	0
82513	433442	202	Generator				0	0	0	0
82513	433443	202	Generator				0	0	0	0
82513	433444	202	Generator				0	0	0	0
82513	433445	202	Generator				0	0	0	0
82513	433446	202	Generator				0	0	0	0
132653	435512	195	Generator				0	0	0	0
137976	435522	195	Generator				0	0	0	0
137976	435523	195	Generator				0	0	0	0
138791	422748	173	Generator				0	0	0	0
132182	400404	162	Generator				0	0	0	0
129434	390240	157	Generator				0	0	0	0
5023	387253	149	Generator				0	0	0	0
5023	387254	149	Generator				0	0	0	0
45882	387483	135	Generator				0	0	0	0
83509	416748	135	Generator				0	0	0	0
83509	416749	135	Generator				0	0	0	0
133802	405963	110	Generator				0	0	0	0
70989	281036	101	Generator				0	0	0	0
34961	321188	94	Generator				0	0	0	0
34961	321189	94	Generator				0	0	0	0
120956	361525	93.8	Generator				0	0	0	0
116813	372297	86	Generator				0	0	0	0
116813	372298	86	Generator				0	0	0	0
116813	372299	86	Generator				0	0	0	0
16211	403396	86	Generator				0	0	0	0
16211	403879	86	Generator				0	0	0	0

Table B-4 (Continued)
PAR1110.2 - Solid and Hazardous Waste Estimates

Facility ID No.	Appl. No.	Engine HP	Engine Use	(d)(1)(B) Reduced Limits, 500+ HP 7/1/10	(d)(1)(B) Reduced Limits <500 HP 7/1/11	(d)(1)(C) Reduced Limits Biogas 7/1/12	Electric Engine, lb	New Cat Ox, lb	Upgrade Cat Ox, lb	SCR Cat, lb
16211	403881	86	Generator				0	0	0	0
16211	403882	86	Generator				0	0	0	0
16211	403884	86	Generator				0	0	0	0
16211	403886	86	Generator				0	0	0	0
129025	388842	80	Generator				0	0	0	0
129664	391023	80	Generator				0	0	0	0
115471	409783	74	Generator				0	0	0	0
115471	409784	74	Generator				0	0	0	0
115471	409785	74	Generator				0	0	0	0
43759	434971	800	Compressor				0	0	0	0
43759	434972	800	Compressor				0	0	0	0
43759	434973	800	Compressor				0	0	0	0
22265	434975	800	Compressor				0	0	0	0
22265	434976	800	Compressor				0	0	0	0
22265	434977	800	Compressor				0	0	0	0
013088	342013	700	Compressor				0	0	0	0
013088	416840	700	Compressor				0	0	0	0
134325	407959	607	Compressor				0	0	0	0
134325	407960	607	Compressor				0	0	0	0
134325	407961	607	Compressor				0	0	0	0
134326	407963	607	Compressor				0	0	0	0
134326	407964	607	Compressor				0	0	0	0
134326	407965	607	Compressor				0	0	0	0
134329	407967	607	Compressor				0	0	0	0
134329	407968	607	Compressor				0	0	0	0
134329	407969	607	Compressor				0	0	0	0
83111	385480	585	Compressor				0	0	0	0
18517	434978	530	Compressor				0	0	0	0
18517	434979	530	Compressor				0	0	0	0
18517	434980	530	Compressor				0	0	0	0
001703	331499	465	Compressor				0	0	0	0
8309	342750	450	Compressor				0	0	0	0
53745	350036	415	Compressor				0	0	0	0

Table B-4 (Continued)
PAR1110.2 - Solid and Hazardous Waste Estimates

Facility ID No.	Appl. No.	Engine HP	Engine Use	(d)(1)(B) Reduced Limits, 500+ HP 7/1/10	(d)(1)(B) Reduced Limits <500 HP 7/1/11	(d)(1)(C) Reduced Limits Biogas 7/1/12	Electric Engine, lb	New Cat Ox, lb	Upgrade Cat Ox, lb	SCR Cat, lb
50645	350037	415	Compressor				0	0	0	0
111116	388705	405	Compressor				0	0	0	0
140028	429785	400	Compressor				0	0	0	0
66086	419537	365	Compressor				0	0	0	0
66086	419538	365	Compressor				0	0	0	0
019159	331495	330	Compressor				0	0	0	0
22092	367195	292	Compressor				0	0	0	0
800041	326508	220	Compressor				0	0	0	0
123664	370691	203	Compressor				0	0	0	0
94117	347693	200	Compressor				0	0	0	0
134328	407966	195	Compressor				0	0	0	0
134330	407970	195	Compressor				0	0	0	0
89852	401453	194	Compressor				0	0	0	0
64375	386532	158	Compressor				0	0	0	0
139380	424742	158	Compressor				0	0	0	0
139380	424743	158	Compressor				0	0	0	0
139380	424744	158	Compressor				0	0	0	0
49572	434072	153	Compressor				0	0	0	0
49572	434472	153	Compressor				0	0	0	0
49572	434473	153	Compressor				0	0	0	0
49572	434474	153	Compressor				0	0	0	0
109393	317735	149	Compressor				0	0	0	0
109393	317738	149	Compressor				0	0	0	0
109393	317742	149	Compressor				0	0	0	0
111345	324916	145	Compressor				0	0	0	0
18650	328168	145	Compressor				0	0	0	0
16211	403397	119	Compressor				0	0	0	0
123664	406670	539	Other				0	0	0	0
001703	426335	815	Pump				0	0	0	0
001703	373968	814	Pump				0	0	0	0
96562	353382	750	Pump				0	0	0	0
001703	356818	700	Pump				0	0	0	0
133829	406061	526	Pump				0	0	0	0

Table B-4 (Continued)
PAR1110.2 - Solid and Hazardous Waste Estimates

Facility ID No.	Appl. No.	Engine HP	Engine Use	(d)(1)(B) Reduced Limits, 500+ HP 7/1/10	(d)(1)(B) Reduced Limits <500 HP 7/1/11	(d)(1)(C) Reduced Limits Biogas 7/1/12	Electric Engine, lb	New Cat Ox, lb	Upgrade Cat Ox, lb	SCR Cat, lb
139509	425325	524	Pump				0	0	0	0
139509	425326	524	Pump				0	0	0	0
139509	425327	524	Pump				0	0	0	0
111406	416671	512	Pump				0	0	0	0
54773	415033	473	Pump				0	0	0	0
54773	415034	473	Pump				0	0	0	0
125016	374784	429	Pump				0	0	0	0
16239	420868	405	Pump				0	0	0	0
96562	364871	395	Pump				0	0	0	0
96562	364887	395	Pump				0	0	0	0
98380	292781	369	Pump				0	0	0	0
98380	292782	369	Pump				0	0	0	0
98380	292784	369	Pump				0	0	0	0
98380	292785	369	Pump				0	0	0	0
57555	420687	369	Pump				0	0	0	0
108286	313977	365	Pump				0	0	0	0
108293	336542	365	Pump				0	0	0	0
108288	339584	365	Pump				0	0	0	0
070303	405402	365	Pump				0	0	0	0
54771	415036	350	Pump				0	0	0	0
16239	321174	329	Pump				0	0	0	0
16239	321175	329	Pump				0	0	0	0
16239	321176	329	Pump				0	0	0	0
16239	321177	329	Pump				0	0	0	0
52718	342367	321	Pump				0	0	0	0
52718	342369	321	Pump				0	0	0	0
87640	342373	321	Pump				0	0	0	0
94996	359880	310	Pump				0	0	0	0
94998	407123	310	Pump				0	0	0	0
95000	439777	310	Pump				0	0	0	0
94677	428124	305	Pump				0	0	0	0
5322	422131	289	Pump				0	0	0	0
52886	388444	246	Pump				0	0	0	0

Table B-4 (Continued)
PAR1110.2 - Solid and Hazardous Waste Estimates

Facility ID No.	Appl. No.	Engine HP	Engine Use	(d)(1)(B) Reduced Limits, 500+ HP 7/1/10	(d)(1)(B) Reduced Limits <500 HP 7/1/11	(d)(1)(C) Reduced Limits Biogas 7/1/12	Electric Engine, lb	New Cat Ox, lb	Upgrade Cat Ox, lb	SCR Cat, lb
52886	388445	246	Pump				0	0	0	0
52886	388447	246	Pump				0	0	0	0
52886	388449	246	Pump				0	0	0	0
52883	388459	246	Pump				0	0	0	0
52883	388462	246	Pump				0	0	0	0
070309	333800	225	Pump				0	0	0	0
070292	334717	225	Pump				0	0	0	0
68181	363123	225	Pump				0	0	0	0
070290	363870	225	Pump				0	0	0	0
119118	352647	220	Pump				0	0	0	0
119118	352648	220	Pump				0	0	0	0
119118	352649	220	Pump				0	0	0	0
113029	329845	211	Pump				0	0	0	0
070280	327127	200	Pump				0	0	0	0
94678	413795	200	Pump				0	0	0	0
95000	286934	180	Pump				0	0	0	0
93720	420807	160	Pump				0	0	0	0
54773	415030	158	Pump				0	0	0	0
54773	415031	158	Pump				0	0	0	0
54773	415032	158	Pump				0	0	0	0
66411	279623	157	Pump				0	0	0	0
2868	279621	145	Pump				0	0	0	0
120455	359159	145	Pump				0	0	0	0
120455	359167	145	Pump				0	0	0	0
070289	390099	145	Pump				0	0	0	0
94676	413796	145	Pump				0	0	0	0
94676	413797	145	Pump				0	0	0	0
94999	286933	137	Pump				0	0	0	0
132772	401914	125	Pump				0	0	0	0
136018	413764	95	Pump				0	0	0	0
125300	375524	80	Pump				0	0	0	0
125300	375526	80	Pump				0	0	0	0
125300	375527	80	Pump				0	0	0	0

Table B-4 (Continued)
PAR1110.2 - Solid and Hazardous Waste Estimates

Facility ID No.	Appl. No.	Engine HP	Engine Use	(d)(1)(B) Reduced Limits, 500+ HP 7/1/10	(d)(1)(B) Reduced Limits <500 HP 7/1/11	(d)(1)(C) Reduced Limits Biogas 7/1/12	Electric Engine, lb	New Cat Ox, lb	Upgrade Cat Ox, lb	SCR Cat, lb
125300	375529	80	Pump				0	0	0	0
14898	389366	75	Pump				0	0	0	0
14898	389368	75	Pump				0	0	0	0
136021	413763	74	Pump				0	0	0	0
Non-Biogas, Non-RECLAIM, BACT, Lean, =>1000										
3671	408492	3352	Generator				0	0	0	0
3671	408493	3352	Generator				0	0	0	0
4773	386614	2682	Generator				0	0	0	0
4773	386615	2682	Generator				0	0	0	0
21123	405486	2494	Generator				0	0	0	0
45973	423225	2307	Generator				0	0	0	0
102153	403632	2095	Generator				0	0	0	0
102153	403633	2095	Generator				0	0	0	0
138267	421271	2083	Generator				0	0	0	0
138267	438902	2083	Generator				0	0	0	0
65818	422450	1737	Generator				0	0	0	0
7796	391786	1468	Generator				0	0	0	0
77033	400718	1468	Generator				0	0	0	0
109524	413078	1468	Generator				0	0	0	0
62589	415988	1468	Generator				0	0	0	0
129827	426299	1468	Generator				0	0	0	0
Non-Biogas, Non-RECLAIM, BACT, Lean, <1000										
7814	412278	898	Generator				0	0	0	0
132087	399874	880	Other				0	0	0	0
132087	399876	880	Other				0	0	0	0
Non-Biogas, Non-RECLAIM, Non-BACT, Rich, =>1000										
14437	288133	1200	Generator	Upgrade			0	0	48	0
14437	288134	1200	Generator	Upgrade			0	0	48	0
14437	341089	1200	Generator	Upgrade			0	0	48	0
118684	350357	1131	Generator	Upgrade			0	0	45	0
118684	350358	1131	Generator	Upgrade			0	0	45	0
Non-Biogas, Non-RECLAIM, Non-BACT, Rich, <1000										
42218	117607	930	Generator	Upgrade			0	0	37	0

Table B-4 (Continued)
PAR1110.2 - Solid and Hazardous Waste Estimates

Facility ID No.	Appl. No.	Engine HP	Engine Use	(d)(1)(B) Reduced Limits, 500+ HP 7/1/10	(d)(1)(B) Reduced Limits <500 HP 7/1/11	(d)(1)(C) Reduced Limits Biogas 7/1/12	Electric Engine, lb	New Cat Ox, lb	Upgrade Cat Ox, lb	SCR Cat, lb
42218	117608	930	Generator	Upgrade			0	0	37	0
42217	117609	930	Generator	Upgrade			0	0	37	0
013088	414452	930	Generator	Upgrade			0	0	37	0
142517	438239	713	Generator	Upgrade			0	0	29	0
85339	274452	315	Generator		Upgrade		0	0	13	0
86055	279345	294	Generator		Upgrade		0	0	12	0
20231	281005	150	Generator		Upgrade		0	0	6.0	0
20231	281006	150	Generator		Upgrade		0	0	6.0	0
10636	316911	148	Generator		Upgrade		0	0	5.9	0
6728	316912	148	Generator		Upgrade		0	0	5.9	0
18435	316913	148	Generator		Upgrade		0	0	5.9	0
2638	172356	145	Generator		Upgrade		0	0	5.8	0
79856	328255	145	Generator		Upgrade		0	0	5.8	0
140598	429420	135	Generator		Upgrade		0	0	5.4	0
82303	329294	94	Generator		Upgrade		0	0	3.8	0
33465	313771	86	Generator		Upgrade		0	0	3.4	0
660	442592	600	Compressor	Upgrade			0	0	24	0
660	442593	600	Compressor	Upgrade			0	0	24	0
660	442594	600	Compressor	Upgrade			0	0	24	0
019159	416831	330	Compressor		Upgrade		0	0	13	0
113251	410103	250	Compressor		Upgrade		0	0	10	0
007417	411022	225	Compressor		Upgrade		0	0	9.0	0
007417	411023	225	Compressor		Upgrade		0	0	9.0	0
007417	411024	225	Compressor		Upgrade		0	0	9.0	0
10827	280612	145	Compressor		Upgrade		0	0	5.8	0
78802	280570	400	Other		Upgrade		0	0	16	0
62851	322538	94	Other		Upgrade		0	0	3.8	0
65818	311320	810	Pump	Upgrade			0	0	32	0
076581	220569	660	Pump	Upgrade			0	0	26	0
95318	281245	634	Pump	Upgrade			0	0	25	0
95318	281247	634	Pump	Upgrade			0	0	25	0
95318	281251	634	Pump	Upgrade			0	0	25	0
95318	281254	634	Pump	Upgrade			0	0	25	0

Table B-4 (Continued)
PAR1110.2 - Solid and Hazardous Waste Estimates

Facility ID No.	Appl. No.	Engine HP	Engine Use	(d)(1)(B) Reduced Limits, 500+ HP 7/1/10	(d)(1)(B) Reduced Limits <500 HP 7/1/11	(d)(1)(C) Reduced Limits Biogas 7/1/12	Electric Engine, lb	New Cat Ox, lb	Upgrade Cat Ox, lb	SCR Cat, lb
95318	281257	634	Pump	Upgrade			0	0	25	0
95318	281260	634	Pump	Upgrade			0	0	25	0
95066	280183	594	Pump	Upgrade			0	0	24	0
94967	280194	594	Pump	Upgrade			0	0	24	0
48820	159531	581	Pump	Upgrade			0	0	23	0
77388	426136	525	Pump	Upgrade			0	0	21	0
77388	426144	525	Pump	Upgrade			0	0	21	0
77388	426145	525	Pump	Upgrade			0	0	21	0
103070	312478	512	Pump	Upgrade			0	0	20	0
68143	187169	500	Pump	Upgrade			0	0	20	0
103052	390939	500	Pump	Upgrade			0	0	20	0
070296	411474	500	Pump	Upgrade			0	0	20	0
076581	220570	450	Pump		Upgrade		0	0	18	0
95977	281266	427	Pump		Upgrade		0	0	17	0
070282	375501	425	Pump		Upgrade		0	0	17	0
070286	410481	425	Pump		Upgrade		0	0	17	0
070292	425052	425	Pump		Upgrade		0	0	17	0
15748	280342	417	Pump		Upgrade		0	0	17	0
15748	280344	417	Pump		Upgrade		0	0	17	0
20231	435450	409	Pump		Upgrade		0	0	16	0
20231	435451	409	Pump		Upgrade		0	0	16	0
94950	280975	400	Pump		Upgrade		0	0	16	0
53733	280999	395	Pump		Upgrade		0	0	16	0
24427	281000	395	Pump		Upgrade		0	0	16	0
95535	281109	395	Pump		Upgrade		0	0	16	0
21104	407532	395	Pump		Upgrade		0	0	16	0
65818	311322	370	Pump		Upgrade		0	0	15	0
58639	435736	370	Pump		Upgrade		0	0	15	0
74396	280341	369	Pump		Upgrade		0	0	15	0
070292	214307	330	Pump		Upgrade		0	0	13	0
070292	214308	330	Pump		Upgrade		0	0	13	0
070282	256758	330	Pump		Upgrade		0	0	13	0
070311	267082	330	Pump		Upgrade		0	0	13	0

Table B-4 (Continued)
PAR1110.2 - Solid and Hazardous Waste Estimates

Facility ID No.	Appl. No.	Engine HP	Engine Use	(d)(1)(B) Reduced Limits, 500+ HP 7/1/10	(d)(1)(B) Reduced Limits <500 HP 7/1/11	(d)(1)(C) Reduced Limits Biogas 7/1/12	Electric Engine, lb	New Cat Ox, lb	Upgrade Cat Ox, lb	SCR Cat, lb
019159	367167	330	Pump		Upgrade		0	0	13	0
019159	367168	330	Pump		Upgrade		0	0	13	0
070290	367776	330	Pump		Upgrade		0	0	13	0
070296	390974	330	Pump		Upgrade		0	0	13	0
21104	414791	330	Pump		Upgrade		0	0	13	0
21104	436827	330	Pump		Upgrade		0	0	13	0
21104	436828	330	Pump		Upgrade		0	0	13	0
21104	436829	330	Pump		Upgrade		0	0	13	0
21104	436830	330	Pump		Upgrade		0	0	13	0
52348	276622	318	Pump		Upgrade		0	0	13	0
52348	276625	318	Pump		Upgrade		0	0	13	0
52348	276627	318	Pump		Upgrade		0	0	13	0
103052	170492	300	Pump		Upgrade		0	0	12	0
070305	267083	300	Pump		Upgrade		0	0	12	0
94940	280974	283	Pump		Upgrade		0	0	11	0
83315	280968	280	Pump		Upgrade		0	0	11	0
83315	280969	280	Pump		Upgrade		0	0	11	0
83315	280970	280	Pump		Upgrade		0	0	11	0
132190	264164	275	Pump		Upgrade		0	0	11	0
83313	280967	270	Pump		Upgrade		0	0	11	0
18239	328539	265	Pump		Upgrade		0	0	11	0
18239	328540	265	Pump		Upgrade		0	0	11	0
94998	280360	250	Pump		Upgrade		0	0	10	0
94999	280365	250	Pump		Upgrade		0	0	10	0
95000	280369	250	Pump		Upgrade		0	0	10	0
83312	280965	250	Pump		Upgrade		0	0	10	0
83312	280966	250	Pump		Upgrade		0	0	10	0
83318	280971	250	Pump		Upgrade		0	0	10	0
84162	306922	238	Pump		Upgrade		0	0	9.5	0
84162	245380	230	Pump		Upgrade		0	0	9.2	0
52885	245384	230	Pump		Upgrade		0	0	9.2	0
52885	245385	230	Pump		Upgrade		0	0	9.2	0
94442	274654	230	Pump		Upgrade		0	0	9.2	0

Table B-4 (Continued)
PAR1110.2 - Solid and Hazardous Waste Estimates

Facility ID No.	Appl. No.	Engine HP	Engine Use	(d)(1)(B) Reduced Limits, 500+ HP 7/1/10	(d)(1)(B) Reduced Limits <500 HP 7/1/11	(d)(1)(C) Reduced Limits Biogas 7/1/12	Electric Engine, lb	New Cat Ox, lb	Upgrade Cat Ox, lb	SCR Cat, lb
11301	215041	225	Pump		Upgrade		0	0	9.0	0
11301	215043	225	Pump		Upgrade		0	0	9.0	0
070295	267086	225	Pump		Upgrade		0	0	9.0	0
11301	311565	225	Pump		Upgrade		0	0	9.0	0
11301	311566	225	Pump		Upgrade		0	0	9.0	0
070300	335327	225	Pump		Upgrade		0	0	9.0	0
070292	368326	225	Pump		Upgrade		0	0	9.0	0
070304	388598	225	Pump		Upgrade		0	0	9.0	0
070290	390942	225	Pump		Upgrade		0	0	9.0	0
070296	390946	225	Pump		Upgrade		0	0	9.0	0
15748	280343	220	Pump		Upgrade		0	0	8.8	0
070298	267085	200	Pump		Upgrade		0	0	8.0	0
070280	267096	200	Pump		Upgrade		0	0	8.0	0
070295	375503	200	Pump		Upgrade		0	0	8.0	0
070302	402959	200	Pump		Upgrade		0	0	8.0	0
070300	433992	200	Pump		Upgrade		0	0	8.0	0
070300	433993	200	Pump		Upgrade		0	0	8.0	0
070300	433994	200	Pump		Upgrade		0	0	8.0	0
2924	264159	190	Pump		Upgrade		0	0	7.6	0
94938	280976	186	Pump		Upgrade		0	0	7.4	0
94937	280978	186	Pump		Upgrade		0	0	7.4	0
94937	280980	186	Pump		Upgrade		0	0	7.4	0
94937	280981	186	Pump		Upgrade		0	0	7.4	0
94995	280355	180	Pump		Upgrade		0	0	7.2	0
94998	280359	180	Pump		Upgrade		0	0	7.2	0
94997	280362	180	Pump		Upgrade		0	0	7.2	0
94999	280364	180	Pump		Upgrade		0	0	7.2	0
95979	281236	180	Pump		Upgrade		0	0	7.2	0
95979	281237	180	Pump		Upgrade		0	0	7.2	0
95979	281240	180	Pump		Upgrade		0	0	7.2	0
95979	281241	180	Pump		Upgrade		0	0	7.2	0
132189	264161	175	Pump		Upgrade		0	0	7.0	0
72489	288630	172	Pump		Upgrade		0	0	6.9	0

Table B-4 (Continued)
PAR1110.2 - Solid and Hazardous Waste Estimates

Facility ID No.	Appl. No.	Engine HP	Engine Use	(d)(1)(B) Reduced Limits, 500+ HP 7/1/10	(d)(1)(B) Reduced Limits <500 HP 7/1/11	(d)(1)(C) Reduced Limits Biogas 7/1/12	Electric Engine, lb	New Cat Ox, lb	Upgrade Cat Ox, lb	SCR Cat, lb
72489	288631	172	Pump		Upgrade		0	0	6.9	0
72489	288632	172	Pump		Upgrade		0	0	6.9	0
81001	246340	170	Pump		Upgrade		0	0	6.8	0
070284	267090	165	Pump		Upgrade		0	0	6.6	0
070284	267091	165	Pump		Upgrade		0	0	6.6	0
2868	274540	157	Pump		Upgrade		0	0	6.3	0
2868	279544	157	Pump		Upgrade		0	0	6.3	0
66403	279545	157	Pump		Upgrade		0	0	6.3	0
66403	279546	157	Pump		Upgrade		0	0	6.3	0
66413	279547	157	Pump		Upgrade		0	0	6.3	0
94928	280632	150	Pump		Upgrade		0	0	6.0	0
94928	280633	150	Pump		Upgrade		0	0	6.0	0
20231	281023	150	Pump		Upgrade		0	0	6.0	0
20231	281024	150	Pump		Upgrade		0	0	6.0	0
070317	267076	145	Pump		Upgrade		0	0	5.8	0
070299	267084	145	Pump		Upgrade		0	0	5.8	0
070283	267094	145	Pump		Upgrade		0	0	5.8	0
66413	279624	145	Pump		Upgrade		0	0	5.8	0
66413	311099	145	Pump		Upgrade		0	0	5.8	0
66413	311100	145	Pump		Upgrade		0	0	5.8	0
070313	328532	145	Pump		Upgrade		0	0	5.8	0
070281	393971	145	Pump		Upgrade		0	0	5.8	0
136235	414451	145	Pump		Upgrade		0	0	5.8	0
070293	436931	145	Pump		Upgrade		0	0	5.8	0
95979	281242	144	Pump		Upgrade		0	0	5.8	0
95979	281243	144	Pump		Upgrade		0	0	5.8	0
52883	245374	143	Pump		Upgrade		0	0	5.7	0
52883	245375	143	Pump		Upgrade		0	0	5.7	0
070307	267080	140	Pump		Upgrade		0	0	5.6	0
95000	280367	140	Pump		Upgrade		0	0	5.6	0
95067	280185	137	Pump		Upgrade		0	0	5.5	0
95067	280190	137	Pump		Upgrade		0	0	5.5	0
95067	280191	137	Pump		Upgrade		0	0	5.5	0

Table B-4 (Continued)
PAR1110.2 - Solid and Hazardous Waste Estimates

Facility ID No.	Appl. No.	Engine HP	Engine Use	(d)(1)(B) Reduced Limits, 500+ HP 7/1/10	(d)(1)(B) Reduced Limits <500 HP 7/1/11	(d)(1)(C) Reduced Limits Biogas 7/1/12	Electric Engine, lb	New Cat Ox, lb	Upgrade Cat Ox, lb	SCR Cat, lb
52884	245388	121	Pump		Upgrade		0	0	4.8	0
96374	280786	116	Pump		Upgrade		0	0	4.6	0
96374	280788	116	Pump		Upgrade		0	0	4.6	0
96374	280790	116	Pump		Upgrade		0	0	4.6	0
3513	399707	109	Pump		Upgrade		0	0	4.4	0
3513	399708	109	Pump		Upgrade		0	0	4.4	0
3513	399709	109	Pump		Upgrade		0	0	4.4	0
71685	280685	100	Pump		Upgrade		0	0	4.0	0
65819	311321	99	Pump		Upgrade		0	0	4.0	0
070295	241359	95	Pump		Upgrade		0	0	3.8	0
20231	281016	75	Pump		Upgrade		0	0	3.0	0
20231	281021	75	Pump		Upgrade		0	0	3.0	0
48523	288615	61	Pump		Upgrade		0	0	2.4	0
48523	288616	61	Pump		Upgrade		0	0	2.4	0
48523	288617	61	Pump		Upgrade		0	0	2.4	0
Survey Total							210,000	1,730	2,847	59,039
District Total							301,724	2,486	4,090	84,826

Description	Total	Upgrade	Three Year	Annual
Solid Waste	301,724			
Hazardous Waste Recycled		2,454	3,946	1,315
Hazardous Waste Disposed		1,636	87,457	29,152

Notes

Data from SCAQMD Staff Survey of ICE engines, 2005. Based on known engines the survey data is representative of 69.6 percent of the ICE engines in the district.
Total district estimated by scaling the survey data by 1.437 (1/0.696)
Oxidation catalyst weight per horsepower = 0.4 pound
SCR catalyst weight per horsepower = 0.5 pound
Average engine weight 14,000 pounds
Assumed all catalyst is hazardous waste
Assumed 60 percent of oxidation catalyst is recycled based on SCAQMD, 2003 Final AQMP Program EIR, 2003. SCR catalyst is not recycled.
Upgrade, Hazardous Waste Recycled = 0.6 x District total upgraded catalyst.
Upgrade, Hazardous Waste Disposed = 0.6 x District total upgraded catalyst.
Three year, Hazardous Waste Recycled = 0.6 x (District total new cat ox + District total upgrade cat ox)

Three year, Hazardous Waste Disposed = 0.4 x (District total new cat ox + District total upgrade cat ox) + District total SCR cat
Annual, Hazardous Waste Recycled = Three year, Hazardous Waste Recycled/3 years
Annual, Hazardous Waste Disposed = Three year, Hazardous Waste Disposed/3 years

APPENDIX E (of the ~~Draft~~Final EA)

COMMENT LETTERS ON THE NOTICE OF PREPARATION AND INITIAL STUDY AND RESPONSES TO THE COMMENT LETTERS

COUNTY SANITATION DISTRICTS
OF LOS ANGELES COUNTY

1955 Workman Mill Road, Whittier, CA 90601-1400
Mailing Address: P.O. Box 4998, Whittier, CA 90607-4998
Telephone: (562) 699-7411, FAX: (562) 699-5422
www.lacsd.org

STEPHEN R. MAGUIN
Chief Engineer and General Manager

May 25, 2007

File No.: 31B-380.10B

Mr. James Koizumi
South Coast Air Quality Management District
21865 E. Copley Drive
Diamond Bar, CA 91765

Dear Mr. Koizumi:

Comments on the Initial Study for Proposed Amended Rule 1110.2

The Sanitation Districts of Los Angeles County (LACSD) are pleased to offer comments on the Initial Study (IS) and Notice of Preparation (NOP) of a draft Environmental Assessment (EA) for Proposed Amended Rule (PAR) 1110.2. The LACSD service area is approximately 800 square miles, and encompasses 78 cities and unincorporated territory within Los Angeles County. LACSD is responsible for wastewater collection and treatment for approximately 5.2 million people in Los Angeles County, as well as solid waste management for a major portion of the County. The facilities we operate include 11 wastewater treatment plants, 3 active landfills, and 3 inactive landfills. Reciprocating engines are an integral part of our operations to provide cost-effective sewage pumping, electrical generation, landfill/digester gas management, and protection of these resources during emergencies.

1-1

1) Chapter 1: Project Objectives

Page 1-3 states that the objective of the project is to partially implement the 2007 AQMP Control Measure MSC-01—Facility Modernization which requires retrofit or replacement of existing equipment with NOx Best Available Control Technology (BACT) "at the end of a predetermined life span." Since PAR 1110.2 sets arbitrary dates for all existing engines to meet natural gas BACT without consideration of useful life or cost recovery, the IS should really present the proposed changes as an *alternative* to the AQMP proposed measure. One way for PAR 1110.2 to become consistent with Control Measure MSC-01 is to use the concept of "useful life" before requiring existing engines to be replaced or retrofitted to meet natural gas BACT.

2) Chapter 1: Emissions Inventory

Page 1-13 through 1-15 estimates the level of excess emissions from the entire engin 1-2
database. This is a very general discussion that is not true for most biogas-fired engines. First,

Recycled Paper

Mr. James Koizumi, SCAQMD -2- May 25, 2007

biogas engines tend to be large engines and are exclusively lean burns (over 75% of biogas engines are 1000 bhp or larger, and 100% are lean burns, according to SCAQMD survey data). The inspection data gathered by SCAQMD (Table 1-6) indicate lean burn engines have a much higher rate of NOx and CO compliance than do rich burns. Second, because most landfill/digester gas engines are larger than 1000 bhp, they are more likely to have CEMS, and thus be in continuous compliance. When these facts are considered together, they suggest that biogas engines do not contribute significantly to the estimated excess emissions shown in Table 1-7 relative to natural gas engines. This point becomes more important, given the claim of the IS on Page 1-17, that emissions from biogas engines far exceed those of natural gas units. This statement may be true when comparing BACT emission limits, but the comparison is misleading when natural gas-fired engines in practice, particularly rich burns, have unfortunately demonstrated non-compliance and excess emissions. The Environmental Assessment should discuss these differences and more accurately report the data regarding biogas engines.

1-2 (cont.)

3) Chapter 1: Control Technology

On Page 1-17 SCAQMD indicates that there have been recent developments in new technologies that may allow emissions from biogas-fired engines that are as low as natural gas engines. We are very concerned that SCAQMD is not providing a clear description of these developments, nor any proof that these technologies function in the long term. For example, the engine at the landfill in City of Industry is primarily a natural gas-fired engine, supplemented with a small percentage of landfill gas. The landfill gas that is combusted in this engine is from a very old landfill that is low in siloxanes and other contaminants that could damage catalyst. Therefore, this is not representative of an engine fueled by landfill gas that meets the definition of biogas proposed in PAR 1110.2.

Also used as an example is fuel treatment and catalytic reduction at the Brea Landfill. In this project, an oxidative catalyst is used in conjunction with a complex fuel treatment system to reduce levels of CO. The operator reports to us that the catalyst on this system cannot make a year of operation without being rotated out for clean-up. Additionally, the operator reports that outlet CO emissions that have been measured in source tests would not meet the proposed CO BACT levels. Since the unit does not have a CEMS, it is not clear what the continuous profile of CO emissions looks like. Clearly, not enough data is present to fully evaluate this system.

1-3

The NOxTech system installed on the landfill gas engine in Woodville, California has been a test case that shows promise, however, no long-term data has been developed that can be reviewed. Also, this process could require the use of natural gas as supplemental fuel that would produce additional emissions, and because it is a SNCR process, may produce unacceptable levels of ammonia slip. Once again, not enough data is available on this system to fully evaluate these issues.

SCAQMD cites landfills in Italy that use the CL.AIR non-catalytic VOC/CO control devices. Once again, long-term CEMS data needs to be produced that demonstrates that the engines could meet the proposed BACT CO requirements, the types of fuel clean-up system needed, and the replacement schedule for the catalyst. The Bowerman Landfill in Orange County is the only facility in the country using this system. To date, they have not collected

Mr. James Koizumi, SCAQMD -3- May 25, 2007

emission data on this system, so there is nothing to substantiate that the BACT CO limit could be met continuously. Also, this system is essentially a thermal oxidizer that needs heat input, such as natural gas or additional landfill gas. Any emissions from these supplemental fuels need to be evaluated. Finally, one would need to determine if this system is compatible with NOx reduction devices. Once again, it is premature to declare this technology a "success".

There is also an engine project in the Bay Area that proposes to use fuel cleanup coupled with CO/ NOx catalysts by Miratech; however, these engines are at least one year away from start-up. At least two years of data, or longer, should be collected before a valid conclusion can be reached on the process. A positive aspect of this project is that the BAAQMD recognizes the uncertainties of this project, and has established an operating threshold in the permit-to-construct on what constitutes success or failure of the catalyst. Unfortunately, our industry is at least three years away from finding out these answers. 1-3 (cont.)

We therefore recommend that the EA and final Staff Report include fuller details of the cited projects, as well as highlight existing uncertainties with the control technologies, particularly in terms of long-term feasibility and continuous compliance, not just source test compliance, with the proposed emission limits. It should also be discussed that all the projects cited above are new installations, so the suitability and economics of retrofitting these technologies to existing units need to be examined once all the emissions and cost data are collected and evaluated. The time lines of these projects indicate that we are at least three years away from having sufficient data to work with.

4) Chapter 2: Environmental Checklist and Discussion

Under "Construction" on Page 2-4, staff states that the possibility of replacing engines with flares will be examined in the Draft EIR. In addition, the EIR should examine the construction impacts of retrofitting existing engines with an advanced fuel treatment system, SCR and CO catalysts, and an ammonia storage and supply system. This level of retrofit could require extensive landfill gas piping re-configuration, building modifications, and stack relocations. 1-4

5) Chapter 2: New Developments

On Page 2-7 under "New Development", staff states that PAR 1110.2 would only require "minor modifications" to buildings or other structures. As stated above, retrofitting existing landfill/digester-fired gas engines with a fuel treatment system and SCR/CO catalyst could require extensive landfill gas piping re-configuration, building modifications, and stack relocations, all of which could be "major modifications." 1-5

6) Chapter 2: Air Quality

Part of the Air Quality assessment that begins on Page 2-8 should address the impacts the proposed project could have on California policies on renewable energy, the use of bioenergy and greenhouse gas reductions mandated by AB 32 and other state policies. 1-6 Additional issues that should be addressed are the consequences of more natural gas usage for the NOxTech and 1-7

Mr. James Koizumi, SCAQMD -4- May 25, 2007

CL.AIR processes, associated ammonia slip emissions from both the NOxTech process and SCR catalysts, and further drain on the Priority Reserve credit bank. 1-7 (cont.)

Further Construction emissions should be evaluated for the scenarios discussed in No. 4 and 5 above. Additional comments related to Air Quality are presented in items 7, 8, and 9 below. 1-8

7) Chapter 2: Solid/Hazardous Waste

Page 2-12 under Air Quality, Page 2-40 in Solid/Hazardous Waste, and Page 2-42 for Transportation/Traffic, all use an estimated catalyst life of three to five years. While this may be reasonable for natural gas applications, catalyst replacements on biogas engines will be much more frequent. Again, such applications are rare and none have a substantial track record; however, an estimated catalyst replacement frequency of 1 year or 8,000 hours of total operation is currently more reasonable for biogas units. This should be considered as added operating costs for biogas facilities, as well as for the associated increased ammonia emissions (i.e., resultant from degraded catalyst), increased solid/hazardous waste burden and disposal costs, and greater traffic, air pollution, and risk to public health related to frequent catalyst changes and removal. 1-9

8) Chapter 2: Public Services

Pages 2-36 and 2-37 address the comments from Association of California Water Agencies (ACWA), and conclude that there will not be any significant public service impacts. We caution against reaching this conclusion without further analysis. Remotely located water purveyors may not have grid power available at pumping facilities, and Diesel generators may not provide the runtime needed for major emergencies (i.e., on-site fuel storage cannot ensure service through wild fires that may last a week or more). In addition, retrofitting existing engines or installing costly CEMS will not make sense on low-use (but not emergency) units. Various water/wastewater/utility jurisdictions have different circumstances, but many have significant investments in gas engines and rely upon them for critical needs. Forcing essential public service agencies to shut down existing engines or look for other means to perform their function may ultimately benefit air quality, however, such actions may have reliability impacts on the public service infrastructure, increase facility health risks (due to new diesels), and will definitely increase the cost of public services, which will be passed on to the ratepayers. Therefore, we feel the EA should address the impacts on "Public Services" as potentially significant. 1-10

9) Chapter 2: Transportation/Traffic

Page 2-9 under Air Quality effects and Page 2-42 in the discussion for Transportation and Traffic mention the impact of additional source testing for engines. We disagree with the analysis using only "one additional test every six years." Since the current requirement is triennial, and the proposed amendment is for testing every two years or every 8760 operating hours—*whichever occurs first*, the EA should conservatively assume testing every 8760 hours, or annually. Increasing engine testing from once every 3 years to annually will notably increase 1-11 workload for LAP-approved testing firms. The increase in contractor traffic and air pollution will likely not be significant, but should be evaluated in the EA. The real concern is that with the proposed restrictions in source testing, such as the ban against pre-tests and any servicing or tuning within 1 week, test cancellations and re-scheduling will increase. This will reduce the availability of test firms. The cancellations and extra demand will also increase source test costs. 1-11 (cont.)

Similarly, Page 2-9 and Page 2-42 touch on the number of CEMS that will be installed as a result of PAR 1110.2. We assert that the currently proposed compliance schedule for new and modified CEMS is unrealistic and will exhaust the available local resources for the manufacture, assembly, integration, installation, and certification of CEMS. Such shortage and increased backlog will increase cost and time needed to achieve compliance. Again, this should be considered in PAR 1110.2, primarily for the compliance and cost aspects, and also the EA for short-term limited impacts on air quality and traffic. We propose extending the CEMS compliance deadlines and consider a tiered compliance schedule such as engines >1000 bhp installing CO CEMS one year earlier than smaller engines installing NOx/CO CEMS. 1-12

We again thank you for this opportunity to comment on the Initial Study and NOP of the draft Environmental Assessment for PAR 1110.2. Please contact Frank Caponi or Tom C. Fang at (562) 699-7411 should you have any questions regarding these comments.

Sincerely,

Stephen R. Maguin

Gregory M. Adams

Gregory M. Adams
Assistant Departmental Engineer
Air Quality Engineering Section
Technical Services Department

GMA:FRC:TCF:ch

CC: Marty Kay, SCAQMD
Laki Tisopulos, SCAQMD

Responses to Comment Letter #1
County Sanitation Districts of Los Angeles County
May 25, 2007

Response 1-1

PAR 1110.2 is considered to implement the 2007 AQMP control measure MCS-01 in part, because it would require affected equipment to be retrofitted or replaced to comply with applicable BACT levels. Although MSC-01 does take into consideration useful life of the equipment, for ICEs affected by PAR 1110.2, useful life has not been precisely defined, especially for ICEs.

Engine replacement with a new engine is not required and may not result in complying with PAR 1110.2 since new engines, without the add-on control technology, are not necessarily cleaner than older engines. The current BACT limits for natural gas engines were established in 1994. These BACT limits would be incorporated into PAR 1110.2. Therefore, only natural gas engines installed before 1994 (i.e., at least 16 years old) would need to be retrofitted.

Even though SCAQMD staff has not verified the claim that commenters may replace ICEs with alternative control technologies, staff has committed to conduct a technology assessment in 2010 to evaluate whether or not cost-effective control technologies are available to allow compliance by biogas engines with the final emission compliance limits in the proposed amended rule, avoid the need for biogas flaring, and eliminate or minimize potential adverse impacts identified by the regulated industry. If the assessment shows a potential for flaring or that cost-effective control technology is not available for biogas engines, staff will return to the Governing Board with a proposal to address any new significant adverse impacts. Depending on the conclusion of the technology assessment, the emission concentration requirements of PAR 1110.2 may need to be modified.

In response to this comment, Alternative D in the Draft EA contains a useful life condition that would extend the requirements an additional two years for equipment that would be less than ten years old in 2010.

Response 1-2

As indicated in Chapter 3 of the Draft EA, the surveys and unannounced compliance testing indicates tat lean-burn engines with CEMS tended to comply with applicable limits, while lean-burn engines without CEMS tended to violate their applicable limit, although the number of test was considered to be too small to be conclusive. For additional information refer to the section entitled “Unannounced Compliance Testing” in Chapter 3. Further, SCAQMD unannounced tests show that when they properly operated and maintained, natural gas engines have significantly lower emissions than biogas engines.

Response 1-3

Based on comments from stakeholders the proposed CO concentration in PAR 1110.2 has been raised from 70 ppm to 250 ppm. Further, in recognizing that additional data are needed for biogas engine control technologies SCAQMD staff are proposing to not submit the proposed biogas emission limits to EPA as part of the SIP submittal for PAR 1110.2. In addition, PAR 1110.2 contains a provision to conduct a technology review in 2010 to assure that cost-effective control technologies are demonstrated and available prior to moving forward with the proposed limits.

Response 1-4

The Draft EA includes a comprehensive analysis of adverse construction impacts from retrofitting existing engines with add-on emissions control equipment and the removal of ICEs and the installation ICE alternatives such as turbines, biogas to LNG plants, etc. Since construction and operations would occur concurrently, peak daily construction and operational criteria pollutants were added together and compared to the operational criteria pollutant thresholds. The analysis and conclusion can be found in Chapter 4 of the Draft EA.

Response 1-5

With regard to the analyiss of impacts from the various compliance options, refer to the Response to Comment 1-4.

Response 1-6

Before the future biogas emission limits go into effect, AQMD staff will conduct a technology assessment in 2010 to assure that feasible retrofit controls are available for biogas engines. This will prevent replacement of ICEs at biogas facilities with continuous flaring. It is unlikely that biogas facilities would replace ICEs with electrification only because biogas must be treated.

In the Draft EA, the worst-case scenario assumed that all ICEs at digester facilities are replaced with gas turbines or microturbines and all ICEs at landfill gas operations are replaced with biogas to LNG plants and would obtain electricity from the power grid. Gas turbines were chosen for digester gas facilities because they are the least efficient of the replacement options of boilers and fuel cells and most digester facilities do not have sufficient room to install biogas to LNG plants. It was assumed that all landfill gas operators would replace ICEs with biogas to LNG plants and would obtain electricity from the power grid, since this would not only remove the electricity provided to the grid, but would require that landfill gas facilities use energy from the grid. The details of this analysis and the conclusion with regard to PAR 1110.2's effect on energy and renewable energy polices in California can be found in the "Energy" section in Chapter 4 of the Draft EA.

Greenhouse gas impacts form implementing APR 1110.2 are evaluated in the "Air Quality" section of Chapter 4 of the Draft EA. Staff has concluded that for some categories of ICEs, replacing ICEs with electric motors would cost less than complying with PAR 1110.2 for an estimated 225 existing non-biogas ICEs. SCAQMD staff assumed as a conservative analysis that operators of 169 existing non-biogas ICEs would replace their existing engines with electric motors. Based on this analysis, PAR 1110.2 would result in an overall CO2 reduction from existing CO2 emission levels from the replacement of existing non-biogas engines with electric motors.

Response 1-7
The NOxTech and CL.AIR technologies are intended for use with biogas engines. They do not require any additional natural gas use because any supplemental heat required by these devices can be provided by biogas rather than natural gas.

NOxTech and SCR controls may have some ammonia slip emissions. It is not clear why PAR 1110.2 would affect Priority Reserve credits. Operators who choose to retrofit existing engines to comply with PAR 1110.2 would be reducing emissions and, therefore, would not be subject to offset requirements. Similarly, operators who replace existing ICEs with new engines would also be reducing emission and would also not be subject to offset requirements.

Response 1-8
With regard to consturction emissions impacts, refore to Response to Comment 1-4.

Response 1-9
The proposed project assumes the use of biogas pretreatment. SCAQMD staff assumed that facility operators would use carbon adsorption to remove biogas impurities that would poison catalyst. The additional vehicle trips and cost for carbon adsorbion were included in the Draft EA analysis. Because biogas pretreatment was included in the analysis, and based on available information, SCAQMD staff assumes that catalyst replacement would occur every three years.

Response 1-10
PAR 1110.2 does not require electrication of engines; however SCAQMD staff believes that facility operators may replace existing engines with electric motors which may be less costly than complying with PAR 1110.2 requirements.

Based on the current version of PAR 1110.2, which would require fewer CEMS than the original version of PAR 1110.2 circulated with the IS, SCAQMD staff has not identified any remote locations that would require a CEMS.

If a water agency operator wants to electrify an engine, and is concerned about a diesel engine providing adequate run time in an emergency, there are other complaince options. The existing natural gas engine and pump could be used as an emergiency back-up to the electrical pump. Diesel engines can also be converted to run primarily on natural gas with a small amount of diesel fuel, which would signifcantly extend the run time of the engine.

A low usage exception from the CEMS requirement has also been added that addresses the commentor's concern about low-use units.

Response 1-11
It is possible that operators of engines without CEMS may need to conduct one or two additional tests every three years. However, staff estimates that the proposed new low-use exception (less than 2,000 hours between tests) would allow about 159 engines to remain on a once-in-every three-years schedule. Semi -annual source tests were assumed in the air quality, and transportation analyses in the IS and Draft EA.

SCAQMD staff does not understand how the prohibition of pre-tests and the limitations on pre-test maintenance will cause tests to be canceled and rescheduled. It is more likely that testing will be reduced, since operators would be prohibited from hiring a test contractor to do a pre-test, find that engine repairs are needed, and then reschedule the reported test for a later date. SCAQMD staff, therefore, agrees that the increase in contractor traffic will not be significant and, as a result, need not be analyzed further in the Draft EA.

Response 1-12

Staff has proposed a revised schedule so that CEMS would be installed in three phases over a three-year period. Also, the revised thresholds will reduce the number of engines requiring CEMS to about 83. Because of the timesharing and electrification possibilities, the number of actual CEMS systems could be as low as 24, further reducing potential traffic impacts.

EASTERN MUNICIPAL WATER DISTRICT

SINCE 1950

Board of Directors

President
David J. Slawson

Vice President
Ronald W. Sullivan

Treasurer
Joseph J. Kuebler, CPA

Randy A. Record
Philip E. Paule

Board Secretary
Rosemarie V. Howell

General Manager
Anthony J. Pack

Director of the Metropolitan Water District of So. Calif.
Randy A. Record

Legal Counsel
Redwine and Sherrill

May 25, 2007

Mr. James Koizumi
South Coast Air Quality Management District
21865 E. Copley Drive
Diamond Bar, CA 91765

Dear Mr. Koizumi:

Eastern Municipal Water District (EMWD) appreciates the opportunity to comment on the Proposed Amended Rule (PAR) 1110.2 Draft Environmental Assessment (DEA). EMWD provides drinking water, fire flow, wastewater collection, treatment and reclamation services to a 555 square mile service area in western Riverside County including the communities of Moreno Valley, Perris, Hemet, San Jacinto, Menifee, Sun City, Murrieta, and Temecula and surrounding unincorporated areas. In support of EMWD's mission, EMWD operates approximately 70 ICEs ranging from 95 brake horsepower (bhp) to 1970 bhp. One of the primary reasons EMWD operates these engines is to ensure and maintain the reliability of our services, especially during catastrophic events such as fires, floods and earthquakes. 2-1

As noted above, reciprocating engines are an integral part of our operating philosophy given our continuous need to have reliable pumping and electrical power generation at all times. Engines are also an important means for the effective management and utilization of digester gas, a bi-product of the wastewater treatment processes, which EMWD views as a valuable resource of renewable energy. In addition, the State of California through its Climate Action Plan and AB32 has intended that renewable fuels be part of the solution for reducing the State's greenhouse gas carbon footprint. This fact should be considered by the South Coast Air Quality Management District (SCAQMD) as it formulates new requirements affecting the utilization of digester gas (and landfill gas) by ICEs.

The comments presented below identify the concerns that EMWD has concerning the Draft Environmental Assessment.

Initial Study, Chapter 2 – Environmental Checklist, III. Air Quality

While the DEA generally claims that the proposed amendments to Rule 1110.2 will not require the electrification or replacement of existing engines with other non-internal combustion type equipment (fuel cells, solar, etc.) or hinder the installation of new engines because the requirements are focused on additional 2-2

Mailing Address: Post Office Box 8300 Perris, CA 92572-8300 Telephone: (951) 928-3777 Fax: (951) 928-6177
Location: 2270 Trumble Road Perris, CA 92570 Internet: www.emwd.org

Mr. James Koizumi, SCAQMD 2 May 25, 2007

compliance monitoring requirements and lowering of emission limits, it fails to note that these new requirements may push current engine operators (and those entities that might normally consider the use of internal combustion engines in new operations) to choose other alternative power (mechanical and/or electrical) strategies. These include the use of electric motor-driven equipment rather than engine-driven equipment. Because public water and wastewater agencies are providing essential public services (drinking water, fire flows, sewage collection and treatment, water reclamation, etc.) the vast majority of facilities must remain in service at all times, especially during disasters such as fires and earthquakes, both common threats in Southern California.

Currently, the use of engine-driven equipment has supported that reliability. However, the proposed requirements of this rule are so costly (capital and operations and maintenance) that it is likely that many existing and future engine operations will be converted to electric motors. In order to provide the same level of reliability that currently exists with the use of engines, operators will have to install diesel-fueled, engine-driven emergency electrical generators. The analysis that is included in this section, fails to evaluate the new emissions and the cancer health risk (chronic) that would be associated with these diesel-fueled generator engines (operation as opposed to construction emissions/risks). These emissions and added cancer burden should be evaluated. 2-2 (cont.)

Additionally, the analysis includes statements noting the Landfill industry's comments that the added cost for installation of CEMS would make flaring of landfill gas an economic alternative to installing SCR and that that would be examined as part of the Draft Environmental Assessment, and if it were found to be probable, that the related construction emissions from replacing engines with flares would be analyzed. EMWD has several comments regarding this analysis.

Wastewater agencies (of which EMWD is one of) are likely to have the same issue. Wastewater processes naturally generate digester gas which is currently used as a fuel and combusted most often in internal combustion engines. The cost of CEMS and meeting proposed lower BACT limits for biogas engines will likely cause wastewater agencies to divert the digester gas to waste gas flares rather than incur costs that would be prohibitive when considered against the return on investment. Hence, the emissions from this same gas diversion at wastewater agencies should be considered as well. It should also be noted that not only may there be emissions related to construction for new flares but there will be the operating emissions from these flares as well. If gas diversion at either or both of these source categories (landfills and wastewater facilities) takes place, the flares will operate 24 hours per day, 365 days per year. Additionally, wastewater agencies will need reliability. Hence, new diesel-fueled, engine-driven emergency electrical generators will be installed to provide the necessary reliability of newly electrified processes. These additional construction and operating emissions and added cancer risk should also be evaluated as part of this analysis.

<u>Initial Study, Chapter 2 – Environmental Checklist, VI. Energy</u>

As noted in the above discussion, the proposed amendments to Rule 1110.2 will result in operators incurring substantial additional costs due to the capital acquisition and operating and maintenance costs associated with the increased monitoring (CEMS, portable analyzer monitoring, increase in emissions source testing frequency and number of load conditions 2-3

Mr. James Koizumi, SCAQMD 3 May 25, 2007

tested, etc.) and the more stringent emissions limitations (BARCT to BACT and distributed generation). These added costs, especially when considered on small engines (those less than 1000 brake horsepower), will likely drive many engine operators to electrify. The analysis done for the impacts to energy do not account for this added electrical demand. The analysis should also account for the energy demand impacts that will be associated with any diversion of landfill and digester gas to flares that will also negatively impact energy demand. The diversion of digester gas to flares should also be analyzed along with landfill gas diversion with regard to the negative impact it will have upon the State's goals for renewable energy programs and how it will affect power and natural gas utility systems and local and/or regional energy supplies. 2-3 (Cont.)

Another area discussed is the impact upon the demand for natural gas. The DEA discusses the impact that SCRs may have in reduced engine efficiency. This decreased efficiency will create a higher demand for natural gas consumption by these SCR outfitted engines. While many of the largest engines operating in the South Coast Air Basin are lean-burn engines (the type of engine that would require an SCR for NOx control), the majority of engines in the Basin are rich-burn engines requiring non-selective catalytic reduction (NSCR) to reduce pollutants. Existing BARCT engines would have to retrofit these systems with larger NSCR catalyst beds in order to attain the current proposed BACT limits. The DEA analysis should include any reduced engine efficiency that these engines may incur and any associated increase in fuel demand. Also, emissions control systems that may achieve the proposed emission limitation for distributed generation should be evaluated as well for any new demand on natural gas due to achieving these standards. 2-4

Under the section that discusses "Electricity Usage from Electric Motors" the analysis discusses the impacts from an estimated conversion of 22 two stroke engines to electric motors. The analysis then discusses the impact of one company's (Hanover Compressed Natural Gas Company) conversion of natural gas engines to electric motors. This analysis should include the impact from estimating how many other natural gas-fired engines will convert to electric motors as well as the impacts from the biogas engines converting (landfill and digester gas). In fact, since CEQA requires an analysis of all potential adverse effects flowing from the proposed rule, the analysis should determine the estimated impacts from a complete conversion of existing internal combustion engines less than 1000 bhp to electric motor-driven equipment. 2-5

Initial Study, Chapter 2 – Environmental Checklist, XIV. Public Facilities

In comments made by the Association of California Water Agencies (ACWA), ACWA suggested that PAR 1110.2 might take away the option to utilize engines from member agencies, thereby negatively impacting their ability to provide reliable services such as delivery of water for fire suppression. The SCAQMD's analysis provided in this section states that PAR 1110.2 would not require the removal of internal combustion engines, but would require some retrofits for monitoring and/or emission reductions. It further states that PAR 1110.2 would not interfere with a water agency's ability to supply water for fire fighting nor negatively impact fire fighting. While it is true that the proposed requirements do not specifically require the replacement of engines with electric motor-driven equipment, as noted above the significant costs associated with these requirements will push many engine operators to replace their existing engines with electric motors and likely cause new project proponents to shift to electric motors in place of engines. Hence, while not specifically requiring engine replacement, the proposed amendments will effectively have that end result. The DEA should evaluate and discuss the potential 2-6

Mr. James Koizumi, SCAQMD 4 May 25, 2007

impacts, including the potential loss of public water supply system reliability (fire flows, drinking water, etc.). ACWA's issue was that if member agencies replaced all engine-driven equipment with electric motor-driven equipment, it would make them more susceptible to the kind of disasters that affected Arrowhead Manor Water Company (AMWC) that lost all ability to provide water supply for drinking and fire protection when the fire burned all power lines in the area supplying power to AMWC electrified facilities. EMWD feels that the SCAQMD's analysis is incomplete, especially when it identified water agencies within EMWD's service area that do not utilize engines yet obtain water from EMWD which does rely upon the use of engine-driven pumps to convey drinking and fire suppression water. 2-6 (cont.)

EMWD sincerely appreciates this opportunity to comment on the PAR 1110.2 Draft Environmental Assessment. Should there be any questions or the need for additional information regarding these comments, please contact Mr. Edward Filadelfia at (951) 928-3777, extension 4318 or at filadele@emwd.org. Thank you.

Sincerely,

Jayne Joy, P.E.
Director, Environmental & Regulatory Compliance

JJ/tm

Cc: Anthony Pack, General Manager
Ravi Ravishanker, Deputy General Manager
Michael Garner, Assistant General Manager, Resource Development
Michael Luker, Assistant General Manager, Operations and Maintenance
Curt Coleman, Attorney, Law Offices of Curtis L. Coleman
Records Management
File

J:\ENVIRONMENTAL\SCAQMD DEA\SCAQMD DEA EMWD COMMENT LTR Final.doc

Responses to Comment Letter #2
Eastern Municipal Water District
May 25, 2007

Response 2-1
See Response 1-6 regarding renewable energy and greenhouse gases.

Response 2-2
Adverse air quality impacts from diesel particulate exhaust from emergency generators are evaluated in the Draft EA. The use of emergency generators would generate addition criteria pollutants, but with the reductions from PAR 1110.2, the criteria pollutants from backup generators would be less than significant. Noncarcinogenic health risk from ammonia slip was evaluated in the Draft EA and found to be less than significant.

The carcinogenic and noncarcinogenic health risk from diesel exhaust particulate from emergency ICEs are evaluated in the Draft EA and determined to be significant.

Se the analysis in the "Air Quality" section in Chapter 4 of this Draft EA for the details of this analysis.

With regard to the issue of biogas flaring, refer to Response to Comment 1-6.

Response 2-3

See Response to Comment 1-6 regarding the issue of biogas flaring and renewable energy.

PAR 1110.2 has been modified since the release of the NOP to include a low use exception. The low use exception that would ICEs from monitoring and emission control technology if engines are used less than 500 hours or 1,000 MMBtu annually, allowed for CEMS sharing. These changes should resolve the commenter's concern about facility operators replacing existing ICEs with electric motors.

Response 2-4
Based upon information obtained from a leading catalyst supplier, catalysts designed to meet BACT limits do not cause additional pressure drop for the engine, so there would not be any efficiency impact as asserted by the commentor. As a result, reduced engine efficiency with an associated increase in demand for fuel is not expected to occur, and therefore is not anlyzed futher in the Draft EA.

Response 2-5
Because of revisions to PAR 1110.2, AQMD staff does not believe that two stroke engines would be electrified. Instead, operators would install oxidation catalysts.

See Response to Comment 2-3 regarding the addtion of a low use exception.

See Response to Comment 1-6 regarding impacts from electrification.

Response 2-6

If a water agency decides to electify a natural gas engine water pump, there are several ways to address reliability during electrical outages. Either an emergency diesel generator can be installed, or the natural gas engine and pump can be retained as emergency backup. However, as indicated in Response to Comment #1-1, PAR 1110.0 has been modified to include a technology assesssment by 2010 to assure that feasible retrofit controls are avaliable for biogas engines. Based on the results of the technology assessment, PAR 1110.2 will be revised as necessary.

APPENDIX F (of the Final EA)

COMMENT LETTERS ON THE DRAFT ENVIRONMENTAL ASSESSMENT AND RESPONSES TO THE COMMENT LETTERS

Bear Valley
Electric Service
A Division of Golden State Water Company

December 17, 2007

Mr. James Koizumi
South Coast Air Quality Management District
c/o CEQA
21865 Copley Drive
Diamond Bar, CA 91765-4182

Subject: Comments on Draft Environmental Assessment for Proposed Amended Rule 1110.2 – Emissions from Gaseous- and Liquid-Fueled Internal Combustion Engines (ICEs)

Dear Mr. Koizumi:

Bear Valley Electric Service (BVES) herewith submits its comments on the South
Coast Air Quality Management District's (SCAQMD) Draft Environmental
Assessment (EA) on Proposed Amended Rule (PAR) 1110.2. This letter supplements
BVES' written comments to Mr. Marty Kay dated September 20, 2007, which are
attached and herein incorporated by reference. 1-1

<u>Comments on Draft EA for PAR 1110.2</u>
BVES has two primary comments regarding the Draft EA and associated PAR 1110.2.
The first is that the SCAQMD proposes to impose major and costly new requirements
on facilities, including BVES' Bear Valley Power Plant (BVPP), that do not fall within
the scope of the SCAQMD's stated Objective of the PAR 1110.2. The second is that
the PAR requirements for additional CEMS equipment and inspections, monitoring
and reporting activities will impose significant costs on BVES' small customer base 1-2
and service area, and will have adverse socio-economic effects on an already strained
local economy.

Before we further discuss our two primary comments, BVES requests that the
SCAQMD staff and Board review and address BVES' previously submitted (attached)
comments on the PAR 1110.2. The attached letter describes BVES' Bear Valley
Power Plant (BVPP) state-of-the-art design, emissions monitoring and controls, and 1-3
emissions limits as set forth in the May 2007 Permits to Operate (PTOs for Facility ID
No. 129033). BVES requests that the staff and Board consider that the PAR 1110.2
would add duplicative and costly equipment, systems and procedures that are already
in place for the BVPP as specified through the BVPP PTOs.

P.O. Box 1547, 42020 Garstin Drive, Big Bear Lake, California 92315
Tel: (909) 866-4678 Fax: (909) 866-5056

In addition to the above, the BVPP PTO emissions limits (NOx 7.3 ppm, CO 36 ppm, and VOC 11 ppm) are significantly more stringent than the PAR 1110.2 limits (NOx 11 ppm, CO 250 ppm and VOC 30 ppm). The SCAQMD-certified NOx CEMS system actively monitors emissions, BVES' operators check CO emissions frequently, the PTOs specify quarterly assessments and documentation of CO concentrations, and BVES voluntarily replaced older design air/fuel (A/F) ratio controllers with state of the art A/F ratio controllers. The SCAQMD PTO conditions, BVPP operator inspections and monitoring, and new A/F ratio controllers represent significant costs for operating this relatively small (8.4 MW) electrical generating plant that is used for meeting peak system loads, emergency power supply during Southern California Edison Company (SCE) transmission system outages of the radial lines supplying the high elevation service area, BVES' own distribution system outages, and overall voltage support during SCE system-wide peaking conditions. 1-4

BVES requests that the SCAQMD recognize that adding more layers of equipment and monitoring through the PAR 1110.2 will not substantially contribute to BVES' or the SCAQMD's mutual goals of ensuring compliance, but it will have substantial adverse impacts on BVES' small customer base due to the high capital and operating costs to comply with the PAR 1110.2 requirements that are redundant to the BVPP PTOs.

<u>PAR 1110.2 Stated Objective Is Not Applicable to the BVPP</u>
Page 2-2 of the Draft EA identifies the following as the Objective of the PAR 1110.2:

1. To implement facility modernization to achieve NOx emissions equivalent to BACT;
2. To achieve further VOC and CO emissions reductions based on the cleanest available technologies;
3. To increase engine compliance through improved monitoring, recordkeeping, and reporting;
4. To implement SB 1298 distributed generation emissions standards for new electrical generating engines; and, 1-5
5. To address issues identified by the Environmental Protection Agency so that 1110.2 can be approved for incorporation into the State Implementation Plan.

The requirements of the PAR 1110.2 should not apply to the BVPP because the BVPP already has equipment, systems, permit conditions, and monitoring, recordkeeping, and reporting procedures that meet or exceed those identified as the Objective of the PAR:

1. The NOx emissions limits specified in the BVPP PTOs are already much lower than SCAQMD-identified BACT for NOx;

2. The BVPP includes the cleanest available technology for controlling VOC and CO emissions, and the BVPP VOC and CO emissions limits are already much lower than the PAR 1110.2 limits;
3. The SCAQMD's recently issued PTOs for the BVPP include monitoring, recordkeeping and reporting requirements that are comparable to the PAR 1110.2,; except for the new PAR CO CEMS requirement, the PAR would impose duplicative requirements for the BVPP and even CO monitoring and recordkeeping are already required through the PTOs; 1-5 (cont.)
4. The BVPP is an existing facility that does not fall under SB 1298; and,
5. The BVPP PTOs already address the EPA issues except for the frequency of source testing, which the EPA recommends at every two years.

The BVPP is a newly constructed facility that overall utilizes the latest in power plant design and equipment. Considering the above point-by-point comparison to the PAR, it is clear that the BVPP already substantively complies with the Objective of the PAR, except for the increased frequency of source testing.

<u>PAR 1110.2 Will Have Adverse Socio-Economic Impacts on BVES Customers</u>
The capital and operational costs of the additional, duplicative requirements of PAR 1110.2 to BVES' service area will be substantial. The addition of CO CEMS, duplicative monitoring, recordkeeping, and reporting on operations, and increased frequency and amount of source testing for the BVPP will have considerable initial and recurring cost impacts on BVES customer rates. The attached letter to Mr. Kay describes the anticipated costs just for the equipment installation of CO CEMS, which when combined with the costs of the other duplicative testing, monitoring, recordkeeping, and reporting provisions of the PAR, will cumulatively add to the socio-economic strain on the struggling economy in the Big Bear Valley. Increased electricity costs to the Big Bear area customers will adversely impact both seasonal and permanent residents, affordable housing, the cost of other public and private services in the Big Bear Valley, and cumulatively and negatively contribute to an already struggling community. As a result, BVES requests that the SCAQMD address the cumulative adverse impacts that would result to BVES' service area. 1-6

<u>Request for BVPP Exemption from New Requirements Under PAR 1110.2</u>
The BVPP is operated to provide emergency and peaking power supplies that cannot otherwise be met due to the operation and capacity limitations on SCE transmission lines serving the BVES area. The BVPP profile does not match SCAQMD staff's emphasis on electrical generation facilities that are mainly used for economic dispatch. 1-7

BVES therefore requests that the SCAQMD staff and Board exempt the BVPP from PAR 1110.2 because it already complies with the Objective, intent and substance of PAR 1110.2 and because of its non-economic basis for operations. To help ensure continued future compliance, BVES is willing to increase the frequency of its source testing for NOx, CO and VOCs from the current three-year interval to every two years. This commitment could be instituted through some administrative action, or through the Board's decision-making on the PAR.

We appreciate your consideration of the above comments and look forward to your response. We also look forward to the staff's and Board's responses to BVES' request for exemption from PAR 1110.2. 1-7 (cont.)

Sincerely,

Tracey L. Drabant

Tracey L. Drabant
Energy Resource Manager

Attachment (Letter to M. Kay dated September 20, 2007)

cc: Marty Kay, South Coast Air Quality Management District
Ken Markling, Bear Valley Electric Service
Emil Schultz, Schulco LLC
Dave Zamorano, Cornerstone Energy Services, Inc.
Rick Lind, EN2 Resources, Inc.

FILE RECEIVED
BY [illegible] DATE 9/26/07

Bear Valley
Electric Service
A Division of Golden State Water Company

September 20, 2007

Mr. Marty Kay
South Coast Air Quality Management District
Science and Technology Advancement
21865 Copley Drive
Diamond Bar, CA 91765

VIA FACSIMILE

Subject: Comments on South Coast AQMD Proposed Amendments to Rule 1110.2

Dear Mr. Kay:

Bear Valley Electric Service (BVES) appreciates the opportunity to provide its comments on the proposed amendments to Rule 1110.2 dated August 7, 2007. BVES owns and operates an 8.4 MW natural gas-fired electric generating plant (Bear Valley Power Plant or BVPP). BVES is a small electric utility that serves approximately 23,000 customers in and around the Big Bear Lake recreational area in the San Bernardino Mountains.

BVES has worked proactively with South Coast Air Quality Management District (AQMD) staff over the last few years to address and reach agreement on acceptable permit operating, monitoring and reporting conditions for the BVPP. Permits to Operate (PTOs) were issued by the AQMD in May 2007 that we believe establish an effective and reasonable emissions control and monitoring program for the BVPP. 1-8

However, in its comments, BVES wishes to relay to the AQMD that the proposed amended rule (PAR) for 1110.2 would substantially increase BVES' operating, monitoring and reporting conditions, and would have significant operational, management, cost and other impacts on BVES and its customers. The PAR would impose numerous new requirements on BVES that are far beyond those established by the recently issued PTOs. As described in the enclosed comments, BVES considers many of the PAR requirements to be unnecessary and redundant to existing conditions of the BVPP PTOs.

P.O. Box 1547, 42020 Garstin Drive, Big Bear Lake, California 92315
Tel: (909) 866-4678 Fax: (909) 866-5056

Before the amendments are finalized and the AQMD Board adopts an amended rule, BVES requests that the AQMD staff and Board carefully consider the burden of these additional requirements on facilities such as BVPP where emissions controls and plant operations already achieve the objectives that are intended by the PAR. BVES further requests that the AQMD specifically consider the marginal, if any, gain to emissions compliance that would be achieved at the BVPP versus the substantial costs and related impacts to BVES electric customers that would result from the PAR. 1-8 (cont.)

Lastly, a continuing concern of BVES is that the AQMD developed the PAR based on a skewed test program of existing facilities. Only eleven lean-burn engines were tested, yet 180 rich-burn engines were tested, leading the AQMD staff to conclude the need for and prepare the PAR to require much more onerous changes for rich-burn engines. The AQMD staff emphasis on mandatory requirements for rich-burn engines, while exempting lean-burn engines from costly retrofits (e.g., CO CEMS), is not defensible given the disproportionate sampling of the facilities. 1-9

BVES looks forward to the opportunity of reviewing and commenting on the AQMD's California Environmental Quality Act document for the PAR. BVES requests that Ken Markling and I are included on all future public notices and documents regarding the PAR. A hard copy of these documents will follow by mail.

Sincerely,

Ken Markling
Operations & Planning Manager
For:
Tracey L. Drabant
Energy Resource Manager

Enclosure

- BVES Comments on the Proposed Amendments to Rule 1110.2
- BVES Comments on the Proposed Changes to the Portable Analyzer Protocol
- Oral Comments Presented by Ken Markling at the September 6, 2007 Workshop

Cc: Mr. James Koizumi, South Coast AQMD
Ken Markling, Bear Valley Electric Service
Emil Schultz, Schulco
Dave Zamorano, Cornerstone Energy Services, Inc.
Rick Lind, EN2 Resources, Inc.

Page 2 of 2

BEAR VALLEY ELECTRIC SERVICE (BVES) COMMENTS ON THE SOUTH COAST AQMD AUGUST 7, 2007 PROPOSED AMENDMENTS TO RULE 1110.2

BVES Comment 1 – Section (e)(3)(A), which addresses Stationary Engine CEMS, indicates that the first CEMS summary report for the period ending June 30, 2008 shall be due on July 30, 2008. This would establish a 30-day time limit for the operator to poll data, prepare the report, perform QA/QC reviews, and then submit the semi-annual CEMS report to the AQMD. BVES' experience is that 30 days is insufficient. Typically, BVES' CEMS contractor takes 30 or more days to deliver its first draft report to BVES. *BVES requests that this provision be changed to no earlier than 60 days, and preferably 90 days.* Extending the submittal due date would also make it more consistent with the AQMD's Annual Emissions Report due date. 1-10

BVES Comment 2 – Section (e)(3)(B) addresses time limits to modify existing or install new CEMS required by the PAR. For public agencies, it allows up to one additional year of time to install or modify CEMS on an existing engine. The additional one year allowance does not apply to private entities such as BVES, which would be subject to the much shorter time limits specified in Table VII. BVES' recent experience is that CEMS contractors are in high demand, and are a relatively new sector of the consulting industry that is having difficulty being responsive to industry needs. *While BVES does not believe that it should be subject to additional CEMS requirements for CO as described in Comment 4 below, if the AQMD does not grant BVES relief from the CO CEMS requirement, then BVES and other private organizations should be afforded the same additional time that public agencies will be afforded.* 1-11

BVES Comment 3 – Section (e)(4) and (f)(1)(D) require the preparation, submittal and AQMD approval of a Stationary Engine Inspection and Monitoring (I&M) Plan that addresses acceptable ranges for engine and control equipment operating parameters. The parameters for the I&M Plan for rich-burn engines include: 1) engine load, 2) maximum deviation of the oxygen sensor set point, and 3) exhaust temperature at the catalyst inlet and temperature change across the catalyst. The I&M Plan is also to identify procedures for: a) diagnosing and notifying the operator (alarming) of engine control malfunctions, b) weekly or 150-operating hour checks of NOx and CO with a portable analyzer, c) daily monitoring, inspection and recordkeeping of: engine parameters, engine elapsed operating hours, hours since the last portable analyzer emissions check for NOx and CO, the deviation of the exhaust oxygen sensor voltage from the air-to-fuel ratio controller set point, and engine control system and air-to-fuel ratio controller faults and alarms that affect emissions, d) procedures and schedules for preventive and corrective maintenance, e) portable analyzer sampling to verify or re-establish the set point following oxygen sensor fault or replacement, f) procedures for reporting noncompliance to the Executive Director within one hour of a non-compliance event, g) procedures for recordkeeping required by the I&M Plan, and h) procedures for I&M Plan revisions and AQMD approval of such revisions prior to changes in emission limits or control equipment. Per the May 2007 AQMD Permits to Operate (PTOs) for its Bear Valley Power Plant 1-12

(BVPP), BVES is already required to inspect, monitor and report on the parameters described above. Because the PTOs already include these procedures that are specific to BVPP operations, *BVES does not believe that another type of I&M Plan should be imposed that would be redundant and costly. Instead, BVES requests that the AQMD accept what has already been required of BVES through the PTOs.* This could be accomplished by adding a provision to this subsection that waives the I&M Plan if acceptable ranges and procedures for inspection, monitoring, reporting and recordkeeping of engine and control equipment operating parameters are already established through a facility's PTO or other AQMD approval. 1-12 (cont.)

Comment 4 – Section (f)(1)(A) would require the addition of seven CO CEMS to the BVPP. *As described in BVES' Comments Presented orally at the September 6 AQMD Workshop (copy attached), BVES requests that it be exempt from CO CEMS.* The costs for equipment purchase, installation, testing, AQMD fees for certification, and other related costs would be greater than $250,000 in the first year and over $100,000 per year thereafter, which is in addition to similar costs already paid and now being paid annually by BVES for its NOx CEMS. The AQMD's May 2007 PTOs for the BVPP already require portable analyzer CO monitoring and recordkeeping to make sure that the BVPP stays in compliance with CO emission limits, and the added costs for CO CEMS for each of the seven engines would be unnecessary and represent a significant increase in costs to BVES' small customer base. An alternative would be for BVES to increase the frequency of its portable analyzer monitoring and recordkeeping in lieu of the CO CEMS. *BVES requests that the AQMD address the alternative of increased portable analyzer CO monitoring and record keeping in lieu of requiring CO CEMS at the BVPP.* 1-13

Comment 5 – Section (f)(1)(A)(vi) establishes exceptions to Rule 218 CEMS requirements, including electronic storage of data in lieu of a strip chart recorder and conducting RATA on the same schedule as source testing. As worded, the provision pertains to "engines that are required to install a CEMS by clause (ii) of this subparagraph…". *BVES requests that the same exceptions be established for existing CEMS as well as CEMS that may be required* "…by clause (i) of this subparagraph." 1-14

Comment 6 – Section (f)(1)(C)(i) proposes to increase the frequency of source testing from every three years to …"every two years, or 8,760 operating hours, whichever occurs first." A sentence is then added to the section that states …"The source test frequency may be reduced to every three years if the engine has operated less than 2,000 hours since the last source test." No rationale is presented for increasing the frequency of the source testing from 3 years to 2 years, or for the selection of 2,000 hours of operation. Further, no consideration is given for the many new testing, monitoring and reporting requirements of the PAR. If the AQMD threshold for source testing is changing to 8,760 hours, then the frequency should not change from 3 years to 2 years, but rather be expressed as …"every 3 years or 8,760 operating hours, whichever occurs first." *BVES therefore requests that the AQMD change this provision to require source testing based only on … "every three years, or every 8,760 hours, whichever occurs first."* 1-15

BVES Page 2 of 6 9/19/07

Comment 7 – Section (f)(1)(D)(x) would waive the I&M Plan requirement if the facility is required to have a NOx and CO CEMS by the PAR, or if the permittee voluntarily has a NOx and CO CEMS that complies with the PAR. BVES was required to have, and has installed and operates, a NOx CEMS in accordance with AQMD permit to construct requirements. In the May 2007 AQMD PTOs, BVES is now required to regularly monitor and record CO as described under Comment 4. Because BVES has a NOx CEMS and because it already regularly monitors and records CO per the terms of the recently issued PTOs, *BVES requests that it be exempt from the I&M Plan requirements.* Comment 3 above provides further detail on the reasons that an I&M Plan would be unnecessary, costly, and redundant to procedures already required through the PTOs. 1-16

Comment 8 – Section (f)(1)(F)(i) and subsequent paragraphs would require electric meter monitoring and CEMS recording for new, non-emergency electrical generating engines. The requirements appear to specifically pertain to facilities that are eligible for emissions credits for heat recovery. However, electrical meter information is not needed by the AQMD for facilities that do not claim emissions credits for heat recovery. *Therefore, Section (f)(1)(F) should be revised to be applicable only to ... "engines subject to the requirements of subparagraph (d)(1)(F)(ii) ... ".* 1-17

Comment 9 – Section (f)(1)(G) requires that portable analyzer tests only be conducted by persons who have completed ..."an appropriate District-approved training program in the operation of portable analyzers and has received a certification issued by the District." *BVES requests that a reasonable time allowance be specified within which operators are to have received the training and certificate.* 1-18

Comment 10 – Section (f)(1)(H)(i) would require an operator to report any noncompliance with Rule 1110.2 or permit condition to the Executive Officer within one hour of the noncompliance or within one hour of the time the operator knew or reasonably should have known of its occurrence. BVES believes that this time limit is unreasonably short and could lead to miscommunication of information. The BVPP has seven engines that are operated intermittently. BVES often starts multiple engines, but its operators cannot simultaneously troubleshoot or investigate a noncompliant engine. If a noncompliant event occurs or is about to occur, the BVES operator shuts down the problem engine and starts another engine in its place. After the engines are running and the operator confirms that the plant is serving load, then the operator will return to the noncompliant engine at a later time to investigate the problem. For an operator to troubleshoot an engine, identify the equipment or other cause of the problem, and determine an estimated time for repairs often involves several hours and sometimes a day or more of investigation. *BVES therefore requests that the AQMD change the reporting time from one hour to one business day, which will help ensure that the operator provides complete and accurate information to the Executive Officer and AQMD staff.* 1-19

Comment 11 – *BVES supports the proposed text addition to Section (h)(10)*, which specifies a start-up exemption limit of 30 minutes, ..."unless the Executive Officer approves a longer period for an engine and makes it a condition of the permit to operate." 1-20

BVES COMMENTS ON SOUTH COAST AQMD PROPOSED CHANGES TO THE (PORTABLE ANALYZER) PROTOCOL FOR THE PERIODIC MONITORING OF NOx, CO, AND 02 FROM STATIONARY ENGINES

BVES has reviewed the proposed protocol for portable analyzer monitoring. At this time, BVES requests that the AQMD defer adoption and provide a future opportunity to review and comment on the proposed revisions to the protocol for two reasons: 1-21

1) the protocol text is directly related to the requirements of Rule 1110.2, and until the AQMD finalizes the proposed amended rule for 1110.2, the text for the protocol cannot be presented for public comment.
2) the proposed forms for linearity and stability tests (Form 1), calibration recordkeeping (Form 2), and periodic monitoring recordkeeping (Form 3) are not included in the draft protocol for review and comment.

\- Attachment to BVES Comments on PAR 1110.2 -

ORAL COMMENTS SUBMITTED BY KEN MARKLING OF BVES AT THE SEPTEMBER 6, 2007 SOUTH COAST AQMD WORKSHOP

Opening: Hello, I am representing Bear Valley Electric Service (BVES), a small electric utility that serves approximately 23,000 customers in and around the Big Bear Lake recreational area in the San Bernardino Mountains.

Introduction: Due mainly to limitations on the three transmission lines that deliver power to our mountaintop community, BVES needed to install its own generation equipment. As of January 2005, we now have seven, rich-burn internal combustion (Waukesha) natural-gas fired engines at our Bear Valley Power Plant (BVPP), for a total of 8.4 MW in capacity. BVES operates the BVPP for peaking power and emergency generation needed during outages caused by forest fires and winter weather.

BVES has a number of comments on the proposed rule, which we will submit in writing by the September 17 deadline. Today, however, BVES will comment on only two of the proposed changes, because if the PAR is implemented as proposed, it would significantly impact BVES' electric customers.

Comment 1: The Proposed Requirement to Add CO CEMS Is Costly and Unwarranted 1-22
The AQMD proposes to require CO CEMS for rich-burn internal combustion engines only. BVES currently has NOx CEMS for each of its seven engines, and already has installed state-of-the-art air-fuel ratio controllers to maintain NOx levels per the AQMD's Permit to Operate (PTO) limits.

The capital cost for installing CO CEMS at the BVPP would be over $100,000. The annual costs for operating, maintaining, testing and reporting to the AQMD would be comparable to the annual costs for NOx CEMS, which averages roughly $70,000 per year. These capital and annual costs <u>exclude</u> BVES staff time for contracting, consulting, reviewing, and reporting to the AQMD which will, in turn, increase. It is estimated that the annual cost for retrofitting and operating CO CEMS equipment the first year would exceed $200,000.

BVPP operators already sample and record CO levels during engine operation. The operators also perform quarterly CO sampling as required by the Permits to Operate (PTOs). Third party Source Emissions testing for CO is also performed every third year.

It is BVES' understanding that the BVPP has the most stringent CO emissions limits (36 ppm corrected) in the SCAQMD for ICEs, and BVES has not been cited for any CO violation. The AQMD already requires BVES to regularly monitor and document CO levels. BVES additionally self-tests for CO levels. The added burden of the capital and annual costs to BVES ratepayers for installing, maintaining, testing and reporting on a CO CEMS at the BVPP is unjustified. There would be no public benefit, but would result in significant public cost to BVES' service area and, in turn, increased rate for its electric service customers.

Comment 2: The Proposed Change in Frequency of Source Testing from Every Three Years to Every Two Years or 8,750 Hours, whichever Comes Sooner, Is Unnecessary
I described earlier the NOx and CO testing and reporting that we undertake at the BVPP. The existing NOx CEMS undergoes Relative Accuracy Test Audits (RATA) annually. The CO is sampled and recorded frequently. Increasing Source Testing from every 3 years to every 2 years would merely duplicate information that is already collected through other testing (e.g., annual NOx RATA) and monitoring (e.g., CO sampling) activities. This would only increase costs to BVES customers without providing new information. 1-23

Summary: Overall, as an electric utility providing a service vital to its customers, BVES has an obligation to provide service at a reasonable cost within the given regulatory framework. By unnecessarily increasing the regulatory cost to do business through costly, unjustified, and unwarranted rules, and without direct public benefit, the AQMD is not allowing BVES to meet its obligation to its customers as an electric utility. 1-24

Thank you for your consideration and the opportunity to address you today. I would like to provide you a copy of these oral comments to be followed by our written comments due on September 17.

Responses to Comment Letter #1
Bear Valley Electric Service
December 18, 2007

Response 1-1
SCAQMD staff strongly disagrees with the opinion expressed by the commenter that the requirements of PAR 1110.2 do not fall within the scope of the SCAQMD's stated Objective of PAR 1110.2 for the following reasons:

First, the commenter incorrectly states later in the comment letter that the objectives of PAR 1110.2 are not applicable to the commenter. The statement of objectives does apply to the objectives of the proposed project, in this case PAR 1110.2, not individual facilities that may be subject to PAR 1110.2. If the equipment operated by the commenter already complies with PAR 1110.2, then no further equipment modifications are necessary.

PAR 1110.2 partially implements 2007 AQMP Control Measure MSC–01 – Facility Modernization, which requires facilities not participating in the NOx Regional CLean Air Incentives Market (RECLAIM) Program to retrofit or replace existing equipment at the end of a predetermined life span to achieve NOx emissions equivalent to BACT. PAR 1110.2 would require affected facility operators to meet existing BACT standards for non-NOx RECLAIM facilities. In order to meet BACT standards some of the existing ICEs would need to retrofit or replace existing equipment. In addition to achieving NOx emission reductions, one of the objectives of PAR 1110.2 is to achieve further VOC and CO emission reductions for new and existing engines based on the cleanest available technologies.

PAR 1110.2 would also increase engine compliance through improved monitoring, recordkeeping and reporting. The additional monitoring, recordkeeping and reporting requirements are expected to eliminate the excess emissions found during unannounced source testing completed by SCAQMD enforcement staff. Additional CEMS, source testing and inspection and monitoring (I&M) would ensure that engines are operating correctly and emissions are below PAR 1110.2 requirements.

PAR 1110.2 would partially implement SB 1298 distributed generation emission standards for new electrical generating engines. The original staff proposal would have required affected engines to comply with CARB's distributed generation standards that, as of January 1, 2007, applied to equipment that does not require local district permits. The CARB standards are based on the emissions from large new central generating stations with BACT. Since large and small electrical generators are already required to meet these standards, the proposed standards would simply extend the same requirements to ICEs that require SCAQMD permits. Based on comments submitted by the Engine Manufacturers Association, staff raised the proposed limits, in lbs/MW-hr, from 0.10 to 0.20 for CO and from 0.02 to 0.10 for VOC. Therefore, one of the objectives was modified from implementing SB 1298 to partially implementing SB 1298.

Finally, a major objective of PAR 1110.2 is to address and correct issues identified by EPA relative to the existing version of Rule 1110.2, so it can be approved for incorporation into the SIP. EPA had five concerns with:

- Lack of an I&M plan similar to CARB' RACT/BARCT document. PAR 1110.2 includes and I&M plan.
- EPA requested that source testing every two years or 8,760 hours instead of every three years. PAR 1110.2 includes source testing every two years.
- Source testing at peak load as well as at under typical duty cycles.
- A removal, or further justification, of the exemptions for engines at ski resorts, the far eastern portion of Riverside County, and San Clemente Island.

Therefore, the objectives of PAR 1110.2 clearly reflect the scope and requirements of PAR 1110.2. Even though all objectives and requirements may not apply to Bear Valley Electric Service (BVES), they not preclude the need for other facilities to meet these objectives and requirements to ensure attainment of criteria pollutants in the SCAB.

Response 1-2
Economic factors direct or indirect are not considered in the Draft or Final Environmental Assessment unless they cause adverse environmental impacts. CEQA Guidelines §15131(a) states that "economic or social effects of a project shall not be treated as significant effects on the environment. An EIR may trace a chain of cause and effect from a proposed decision on a project through anticipated economic or social changes resulting from the project to physical changes caused in turn by economic or social changes… The focus of the analysis shall be on the physical changes." CEQA Guidelines §15131(b) states "economic or social effects of a project may be used to determine the significance of the physical changes cause by the project." CEQA Guidelines §15131(c) states that "economic, social, and particularly housing factors shall be considered by public agencies together with technological and environmental factors in deciding whether change in a project are feasible to reduce or avoid the significant effects on the environment identified in the EIR. CEQA statutes §§21100 and 21151 also state that significant effects are limited to physical conditions. No direct or indirect economic or social effects that could cause physical impacts to the environment were identified as a result of implementing PAR 1110.2.

Permit data indicates that BVES would need to install seven CO analyzers to its internal combustion engines in 2010, resulting in an average annual compliance cost of $16,359, assuming a ten-year equipment life. It would not incur other costs. Therefore, the impact is minimal. Also, see Response 1-6.

Response 1-3
Specific comments have been identified in the attachment to BVES' letter and responses have been prepared.

BVES operates seven rich-burn, 1,695-bhp engines that are currently required by Rule 1110.2 to have a CEMS for NOx. Prior to 1997, Rule 1110.2 also required a CO monitor for such engines. Because SCAQMD testing has found that 28 percent of rich-burn engines tested are in violation of CO emission limits, SCAQMD has proposed to reinstate the requirements for continuous monitoring of CO, in addition to NOx, for large engines. BVES' permits only require a quarterly test for CO, which is not as effective in ensuring compliance as continuous monitoring. BVES' currently permitted CO emission limit is 36 ppm, which is much more stringent than the proposed 250 ppm emission limit in Rule 1110.2, so ensuring compliance with this lower limit through continuous monitoring is much more critical.

Response 1-4
Since BVES already has a NOx CEMS, the cost of adding a CO monitor to the system is relatively small. BVES can pass on the costs to its customers. Further, BVES' equipment already complies with emission limits in PAR 1110.2, so no additional emission control equipment will be required. As a result no further cost will be incurred to purchase, install or maintain emission control equipment. BVES did not provide any specific analysis to show there are "…substantial adverse impacts on BVES' small customer base…" However, SCAQMD staff believes that when the compliance cost is amortized over the life of the equipment, the impacts to the ratepayers should be minimal.

Response 1-5
The emissions limits specified in the BVES permits to operate are already lower than the emission limits of PAR 1110.2. As a result, equipment at the BVES facility already meet most of the objectives of PAR 1110.2 except for the enhanced compliance through improved monitoring, recordkeeping, and reporting. See Response 1-3.

Response 1-6
BVES states that PAR 1110.2 requirements would increase electricity cost to customers, which would adversely impact seasonal and permanent residents, affordable housing, the cost of other public and private services and cumulatively and negatively contribute to an already struggling community. BVES did not provide sufficient information on the expected costs incurred to be able to evaluate the assertions that PAR 1110.2 would adversely affect the economy of Big Bear Valley.

Please see the Response 1-2. Data on total electricity generated by BVES is not publicly available so it is not possible to calculate the additional rate impact from compliance costs associated with the proposed amendments. However, given that Bear Valley Electric Service (BVES) serves about 17,500 residential customers and 2,500 commercial, industrial, and government customers, the impact of the $16,359 annual cost, assuming a ten-year equipment life, on its customers is not expected to be significant.

Response 1-7
Please see Response 1-3, which explains why improved CO monitoring is necessary. BVES offers to source test every two years. BVES is already required by Rule 218 to test at least annually for NOx CEMS certification. PAR 1110.2 will add CO to that requirement. If the engines are used primarily for "emergency and peaking power", they may not have to source test annually for VOC. PAR 1110.2 requires testing every two years or 8,760 hours, whichever occurs first. If the engines operate less than 2000 hours between source tests, the VOC test can be once every three years. SCAQMD rules do not typically exempt individual facilities. Generally, rules apply to specified equipment across the board as a measure of fairness and to enhance inspectors' abilities to enforce rule requirements for similar types of equipment.

Response 1-8
The September 20, 2007 fax from BVES was submitted to the SCAQMD prior to the release of the Draft EA on October 30, 2007; therefore, does not contain comments on the environmental analysis in the draft EA. Instead, the comments in this letter focus only on PAR 1110.2 provisions. In spite of this, specific comments have been identified and responses prepared for each comment. See previous responses 1-1, 1-3, 1-4 and 1-7.

Response 1-9
There is a sound technical basis for having different CO monitoring requirements for lean-burn engines. Because of the high levels of excess air with lean-burn engines, they inherently have much lower and more stable CO emissions than rich-burn engines. AQMD testing confirmed this. With regard to rich-burn engines, see Response 1-3.

Response 1-10
Rule 218 already requires CEMS reports within 30 days of the end of the six-month period.

Response 1-11
Giving public agencies an additional year to comply with the CEMS requirements actually addresses BVES' concern about the availability of CEMS contractors by stretching out the process over a three-year period, instead of a two-year period. BVES is not a public agency and can move faster than a public agency. With regard to financing and hiring contractors, public agencies are typically required to go through lengthy request for proposal processes, which can add substantial time to the contractor selection and hiring process.

Response 1-12
Pursuant to (f)(1)(D)(x) of the PAR, BVES will not be subject to the Inspection and Monitoring (I&M) plan requirements of the PAR because BVES will have NOx and CO CEMS. BVES should apply for a change of permit conditions to remove the parameter monitoring and quarterly CO testing on the current permit once the CO monitor is added to the current CEMS.

Response 1-13
See previous responses 1-1, 1-3 and 1-4. With regard to cost impacts, see Responses 1-2 and 1-6.

Response 1-14
Those exceptions to Rule 218 are intended only for smaller engines under 1,000 bhp that will be required to install a new CEMS. BVES' NOx CEMS already complies with Rule 218 as is.

Response 1-15
Both CARB and EPA require source testing at least every two years, but they have consented to the 2,000-hour exception. The source testing frequency provision is a necessary requirement for approval by EPA to incorporate the rule into the SIP. Incorporating a rule into the SIP is necessary to allow SCAQMD to take credit for anticipated emission reductions and for required attainment demonstration.

Response 1-16

BVES is exempt from I&M plan requirements, but please see previous responses 1-1, 1-3 and 1-4 regarding the need for continuous CO monitoring.

Response 1-17
Subparagraph (f)(1)(F) does not apply to BVES' engines, New electrical generating engines that are subject to this provision will be required to install electric meters in order to be able to determine emissions in pounds per megawatt-hour of electricity produced. As a result, the requested changes are not appropriate.

Response 1-18
BVES will not be required to have portable analyzer training because it will not be subject to I&M plan requirements. Other facilities subject to the portable analyzer training would have up to ten months after the adoption of PAR 1110.2 to complete the training, since that is when I&M plans are to be implemented.

Response 1-19
SCAQMD has revised the PAR 1110.2 reporting requirements substantially. Rule 430, however, currently requires breakdowns to be reported within one hour. If an operator doesn't know the exact cause of non-compliance or expected time for repairs within one hour, the operator does not have to include this information in the breakdown report. For excess emissions detected by a CEMS that are not caused by a breakdown, Rule 218 currently requires a report within 24 hours or the next working day. Other problems may be reported quarterly.

Response 1-20
SCAQMD understands that BVES supports the current proposal in paragraph (h)(10).

Response 1-21
BVES will not be subject to the portable analyzer protocol requirements because it will have a NOx and CO CEMS. The forms attached to the protocol have been on SCAQMD's website since November 2007.

Response 1-22
See previous responses 1-1, 1-3 and 1-4.

Response 1-23
See previous responses 1-7 and 1-15.

Response 1-24
Improved monitoring, testing and reporting in the PAR will improve engine compliance, reduce emissions, and benefit the customers of BVES, as well as all residents within the SCAQMD jurisdiction. Also, see Responses 1-2 and 1-6 regarding costs to do business.